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ATTACHMENTS

Joint Pipeline Office
Comprehensive Monitoring Program

TAPS Maintenance and Sustained Useful Life

1.0 Introduction and Purpose

The Joint Pipeline Office (JPO) is a consortium of seven State and six Federal agencies with responsibilities for regulating the Trans-Alaska Pipeline System and other oil and gas pipelines in Alaska. The JPO came into existence in 1990 and stemmed from a cooperative effort by the Bureau of Land Management and the Alaska Department of Natural Resources.

The JPO Comprehensive Monitoring Program (CMP) reports were initiated to allow for periodic communications with stakeholders on the status of Trans-Alaska Pipeline System (TAPS) compliance issues relative to a specific subject area. Numerous CMP reports on various subjects have been published in recent years; this report is the third such publication specific to the area of Maintenance[1]. This report addresses the work completed to date to identify the various maintenance strategies to preserve the functional requirements of critical TAPS systems.

Both this CMP report and the one previous, focus on the maintenance requirements and strategies necessary to ensure operational safety, environmental responsibility, and functional reliability of TAPS systems and equipment. The requirements for maintenance of the TAPS are principally taken from the following four documents: (1) *Public Law 93-153*, dated November 16, 1973, which amends section 28 of the Mineral Leasing Act of 1920; (2) The *Agreement and Grant of Right-of-Way for Trans-Alaska Pipeline*, dated January 23, 1974, as amended, (hereinafter referred to as the "Grant"); (3) The *Alaska State Lease of Right-of-Way*, dated May 3, 1974 (hereinafter referred to as the "Lease") and (4) 49 CFR Part 195. These documents broadly define the maintenance requirements for TAPS. Public Law 95-153 further states the requirements for renewal of any Federal *Grant of Right-of-Way*, and includes the requirement for consideration of the "useful life" of the system prior to renewal. The Federal *Agreement and Grant of Right-of-Way* for TAPS expires in January 2004 unless renewed. The Alaska State *Lease of Right-of-Way* for TAPS expires in May 2004 unless renewed. The JPO considers the "useful life" of TAPS to be directly related to the design criteria used to build TAPS and the maintenance strategies deployed to preserve the associated functional requirements throughout the life of the system.

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[1] Previous Reports: (1) An Evaluation of Selected Portions of the TAPS Maintenance Program January 1997 – April 1999; (2) Joint Pipeline Office Comprehensive Monitoring Program Report: TAPS Maintenance Program, January 1999 – July 2000, published January 2001.

The work plan leading to this CMP report was designed to (1) comprehensively evaluate Alyeska Pipeline Service Company (APSC) monitoring and maintenance strategies and program structure; (2) identify the maintenance requirements of critical TAPS systems necessary to ensure safety and reliability for continued safe operation and right-of-way renewal; and (3) provide a foundation for continuous improvement to TAPS maintenance strategies.

The JPO is currently looking at TAPS in the added light of renewing the Federal and State Rights-of-Way. A term of up to 30 years duration may be considered if APSC employs best maintenance practices and maintenance strategies that are technically feasible and worth doing in terms of their respective consequences. JPO requires APSC to implement a well-defined maintenance management program that will ensure TAPS integrity and reliability over the term of renewal.

2.0 Requirements

The following provides a summary of the requirements to which JPO has operated with regard to the maintenance and useful life of TAPS:

2.1 Public Law

Public Law 93-153, dated November 16, 1973, was an act to amend section 28 of the Mineral Leasing Act of 1920, and to authorize the trans-Alaska oil pipeline and provide other Federal rights-of-way requirements. Title I of this act includes amendments to Section 28 of the Mineral Leasing Act of 1920. Title I requires the following regarding right-of-ways through any Federal lands:

Regulatory Authority

> (f) Rights-of-way or permits granted or renewed pursuant to this section shall be subject to regulations promulgated in accord with this provisions of this section and shall be subject to such terms and conditions as the Secretary or agency head may prescribe regarding extent, duration, survey, location, construction, operation, maintenance, use, and termination.

Technical and Financial Capability

> (j) The Secretary or agency head shall grant or renew a right-of-way or permit under this section only when he is satisfied that the application has the technical and financial capability to construct, operate, maintain, and terminate the project for which the right-of-way or permit is requested in accordance with the requirements of this section.

Duration of Grant

(n) Each right-of-way or permit granted or renewed pursuant to this section shall be limited to a reasonable term in light of all circumstances concerning the project, but in no event more than thirty years. In determining the duration of a right-of-way the Secretary or agency head shall, among other things, take into consideration the cost of the facility, its useful life, and any public purpose it serves. The secretary or agency head shall renew any right-of-way, in accordance with the provisions of this section, so long as the project is in commercial operation and is operated and maintained in accordance with all of the provisions of this section.

Title II of this amendment is the "Trans-Alaska Pipeline Authorization Act." Title II, in part, requires the following:

Sec. 203. (b) The Congress hereby authorizes and directs the Secretary of the Interior and other appropriate Federal officers and agencies to issue and take all necessary action to administer and enforce rights-of-way, permits, leases, and other authorizations that are necessary for or related to the construction, operation, and maintenance of the trans-Alaska oil pipeline system, including roads and airstrips, as that system is generally described in the Final Environmental Impact Statement issued by the Department of the Interior on March 20, 1972.

2.2 GRANT/LEASE RIGHTS-OF-WAY FOR TRANS-ALASKA PIPELINE

The following requirements of the Federal *Agreement and Grant of Right-of-Way* and the *Alaska State Lease of Right-of-Way*, for the Trans-Alaska Pipeline are the primary maintenance requirements under review:

Principle 3: Permittees shall manage, supervise and implement the construction, operation, maintenance and termination of the Pipeline System in accordance with sound engineering practice, to the extent allowed by the state of the art and the development of technology. In the exercise of these functions, Permittees consent and shall submit to such review, inspection and compliance procedures relating to construction, operation, maintenance and termination of the Pipeline System as are provided for in this Agreement and other applicable authorizations. The parties intend that this Agreement shall not in any way derogate from, or be construed as being inconsistent with, the provisions of Section 203 (d) of the Trans-Alaska Pipeline Authorization Act, 87 Stat. 585 (1973), relating the National Environmental Policy Act, 83 Stat. 852, 42 U.S.C. 4321 *et seq*.

Stipulation 1.18.1: *Surveillance and Maintenance*: During the construction, operation, maintenance and termination of the Pipeline System, Permittees shall conduct a surveillance and maintenance program applicable to the sub-arctic and arctic environment. This program shall be designed to: (1) provide for public health and safety; (2) prevent damage to natural resources; (3) prevent erosion; and (4) maintain Pipeline System integrity.

Stipulation 1.18.3: Permittees shall maintain complete and up-to-date records on construction, operation, maintenance and termination activities performed in connection with the Pipeline System. Such records shall include surveillance data, leak and break records, necessary operational data, modification records and such other data as the Authorized Officer may require.

2.3 USDOT/OPS REGULATORY REQUIREMENT

Currently, the primary regulatory basis for achieving safety goals in the pipeline industry is the set of regulations embodied in Title 49 of the Code of Federal Regulations Parts 190-199. The federal pipeline safety regulations assure safety in design, construction, inspection, testing, operation, and maintenance of natural gas and hazardous liquid pipeline facilities. Key aspects of these regulations are incorporated in Grant/Lease Stipulation 3.2.1

3.0 Background

The following sections provide discussions, which serve to summarize the past work activities and oversight philosophies that capture the context of this CMP effort.

3.1 TAPS MAINTENANCE MANAGEMENT

The Alyeska Pipeline Service Company (ASPC), as operator of TAPS is responsible for the transportation of crude oil from Prudhoe Bay to Valdez and to date has transported 13 billion barrels of oil. As part of the requirements of the Grant/Lease Rights-of-Way for TAPS, APSC developed a maintenance management system (MMS) to (1) provide for public health and safety; (2) prevent damage to natural resources; (3) prevent erosion; and (4) maintain Pipeline System integrity. One of the significant requirements of a MMS is the identification of applicable and cost effective maintenance strategies. These maintenance strategies are first of all dependent on the overall design of the system. The original design of TAPS presented design engineers with numerous technical challenges and as a result a robust TAPS was built which incorporated redundancies and safety factors to account for a wide variety of unknown conditions such as earthquakes and floods. Twenty-five years of operation has provided a critical evaluation of TAPS and has confirmed the original design as being technically sound.

With regards to the identification of suitable maintenance strategies to sustain the functions of TAPS, APSC's initial approach was the use of manufacturer's recommendations as a foundation for their maintenance program. Over the past 25 years, these maintenance strategies have been refined to incorporate various condition monitoring techniques, results from various risk assessments, initiatives driven from root cause failure analyses, results of reliability centered maintenance (RCM) reviews, and good engineering judgment. As a result of the ongoing review of these maintenance practices over the last 25 years TAPS has achieved 99.98% reliability. With regards to pipeline leaks, 27,533 bbls of oil have been spilled which is considered to be less than the 1974 EIS predictions and less than other pipelines in the United States.

In light of executing these formulated maintenance strategies, APSC has developed systems and procedures for ensuring these strategies are deployed at the right time and at the right frequency as well ensuring the associated resources are managed efficiently. APSC uses a computerized maintenance management system called Passport to fulfill part of this role. These systems and procedures are documented in their Maintenance System Manual MP-167.

On the corrective maintenance side, APSC has historically scheduled corrective maintenance with a project-based philosophy. This approach has often led to corrective maintenance being deferred from one financial accounting period to another, allowing the potential for the equipment to go into a failed state before it can be repaired.

Equipment manufacturers often play a role in developing maintenance programs for APSC. There can be serious drawbacks to this however, as equipment manufacturers are usually not informed on the operating context of the equipment, desired standards of performance, context-specific failure modes and effects, failure consequences, and the skills of the operators and maintainers. As a result, schedules compiled by manufacturers are nearly always generic and tend to be equipment specific not function specific.

It is these unknown situations, which has caused JPO concern and has prompted the JPO to review the maintenance strategies of select TAPS sub-systems.

As a result of these concerns and JPO intent to conduct RCM analyses on TAPS, APSC proactively conducted assessments of their maintenance management systems in June 2000, one for the Fairbanks Business Unit (FBU) and one for the Valdez Business Unit (VBU). APSC procured a team of maintenance management consultants, headed by BP Amoco, to conduct these assessments, and has shared the associated philosophy, methodology, scope, and results with the JPO. APSC has communicated openly with JPO throughout these efforts.

Implementation of the results of these assessments has been initiated by APSC with some associated organizational changes.

Subsequently, APSC let a contract to *Erin Engineering, Inc.* to conduct analyses utilizing a version of RCM termed *Streamlined Reliability Centered Maintenance* (SRCM). The application of SRCM was recommended as a result of the BP Amoco Maintenance Management Assessment. APSC applied the SRCM methodology to several sub-systems within TAPS pump stations. Monitoring implementation of the maintenance tasks associated with hidden, safety, and environmental consequence failures, identified through the SRCM process, shall be a part of JPO future work efforts.

3.2 RISK-BASED OVERSIGHT

Since the inception of JPO, it has been the intent to provide oversight to the operation and maintenance of TAPS in a risk-based manner. Over the past years, several comprehensive risk assessments have been completed on TAPS[2], which JPO has considered in development of its comprehensive monitoring programs. It has been the intent of this maintenance and useful life review to provide a "closed loop" to the results of these risk assessments, (i.e. ensure there are monitoring and maintenance tasks in place to protect against high risk, high consequence failures). Accordingly, JPO reviewed these risk assessments in conjunction with the results of this maintenance and useful life effort. The results of this integrated review are provided below in section *5.4 RCM and Risk Based Oversight*.

Other audits such as the owner and government audit(s) of 1993 & 1994 focused on the overall quality plan and areas of concern to employees such as the electrical systems of TAPS. Maintenance strategies of critical systems were not evaluated per se.

The issue of deferred maintenance and inadequate predictive maintenance has been a central theme of many concerned employee complaints for the last 10 years. APSC has received guidance from various consultants on how to improve their business processes that affect maintenance on TAPS.

3.3 JPO POSITION ON TAPS MAINTENANCE AND USEFUL LIFE

The term "useful life" has not been clearly defined in the requirements documents referenced in section 2.0 above, however, the useful life of TAPS seems clearly meant to describe the remaining life of the TAPS physical assets (economic viability is assumed), which is in turn dependent on the following:

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[2] (1) Trans Alaska Pipeline System Risk Assessment, Technica, Inc., January 1991; (2) JPO Comprehensive Monitoring Program, Booz-Allen & Hamilton,Inc., June 1994; (3) Risk Analysis Screening Study for the Trans Alaska Pipeline System, J.R. Taylor/Taylor Associates, May 1995; (4) Screening Risk Analysis Trans Alaska Pipeline System, Capstone Engineering Services, Inc., December 2001

- The original design criteria of those physical assets
- The materials used to build those physical assets
- The installation of those physical assets
- How physical assets have been maintained over the last twenty-five years
- The maintenance requirements to sustain the physical functions of TAPS

However, in light of modern day thinking this definition needs to be taken one step further. Any physical asset is put into service because someone wants it to do something. So it follows that when we maintain an asset, the state which we wish to preserve must be one in which it continues to do whatever its users want it to do. Maintainers serve three distinct sets of customers; the owners of the assets, the users of the assets, and society as a whole. Owners (the owner oil companies) are satisfied if their assets generate a satisfactory return on their investment. Users (APSC) are satisfied if the asset continues to perform to a standard of performance, which they consider to be satisfactory. Society as a whole is satisfied if assets do not fail in such ways, which threaten public safety or the environment.

In Alaska, the state owns royalty oil and is required to pay its portion of transportation costs. This is estimated to be 23% of total transportation costs. As a result, the state of Alaska has a vested interest in ensuring TAPS systems are kept operating reliably and cost effectively.

To most effectively maintain assets, we must gain a crystal clear understanding of the functions of each asset together with the associated performance standards.

If things didn't fail they would not need maintenance, which means the technology of maintenance is all about finding ways to manage failure. Failure management techniques include, predictive, preventive and corrective maintenance, run to failure, and modifications to the design of the asset or to the way it is operated. Each of these categories includes a whole host of options, some more effective than others. Maintainers therefore need to learn what these options are and apply those that are worthwhile to their organization. If they make the right choices, it is possible to improve asset performance and reliability, and at the same time either contain or reduce maintenance costs. If they make the wrong choices, new problems arise while existing problems get worse. This emphasizes that maintainers need to make cost effective decisions when evaluating the different options.

When considering the different failure management options, we also need to bear in mind that failures only attract attention because they have consequences. The severity and frequency of the consequences incurred by the failure determines whether a failure management technique is worth applying. This emphasizes the point that consequences should be known, and as a result, avoided or minimized when making decisions about maintenance.

Another point that needs to be acknowledged in highly resource constrained environments, is applying resources that are needed – people, spares and tools – as cost effectively as possible. This needs to be done in a manner not so cheaply that it damages the long-term functionality of assets, but be minimized throughout their useful lives, not just to the next accounting period.

Finally, determining the maintenance requirements of physical assets depends on people, not only the maintainers, but operators, designers and vendors. Therefore, when making maintenance decisions for the asset, it is beneficial to involve people representing a multitude of perspectives, to develop a common and correct understanding of the functions, potential failures and potential failure effects.

In light of the above, the JPO considers the "useful life" of TAPS to be directly related to the design criteria used to build TAPS and the maintenance strategies deployed to preserve the associated functional requirements throughout the life of the system.

To evaluate the TAPS maintenance, system integrity, and useful life requirements in a comprehensive manner, the JPO intended to conduct: (1) an Asset Maintenance Management (AMM) assessment; and (2) use a process called Reliability Centered Maintenance (RCM) to determine the maintenance strategies of critical TAPS systems in their present operating context. The AMM assessment was to provide a relative measure of the APSC programmatic approach to TAPS maintenance. The RCM analyses were to facilitate identification of the maintenance strategies required for select TAPS systems, to avoid or minimize safety and environmental consequences as well improve system integrity. (Note: The JPO established its approach to evaluating the maintenance and useful life of TAPS in the 1999/2000 Maintenance CMP report.)

It should be noted that APSC introduced the RCM methodology (specifically RCMII) to JPO in 1998, as the company was using this methodology to evaluate the maintenance needs of several TAPS sub-systems (Remote Gate Valve, Mainline Check Valve, Berth Crude Oil Loading Arm, Chicksan Hydraulic Skid, Berth Fenwal Safety System, Berth Servomax Oxygen Analyzer, Berth Vapor Collection System, and Berth Vapor Collection Arm). JPO found that this methodology provided a structured and disciplined approach to tying specific maintenance tasks to the preservation of sub-system functions; the preservation of which is deemed important to public safety, protection of the environment, and pipeline integrity.

To support and facilitate the TAPS RCM analyses, JPO let two contracts: The first is with *Aladon Ltd.*, a company with internationally recognized expertise in Maintenance Management and RCM analyses; the President of the company, Mr. John Moubray, is the author of the textbook *Reliability-centered Maintenance*, used by JPO to facilitate an understanding of RCM and its application. The second contract is with *New Dimension Solutions, Inc.*, (formerly *Spearhead System Consultants, Ltd.*), a full-service, strategic consulting practice that specializes in maintenance management techniques. *New Dimension Solutions, Inc.* provides expert RCM practitioners to facilitate and support the TAPS sub-system analyses.

3.4 APSC Continuous Improvement Commitments

In January of 1999, JPO began discussions with APSC regarding the AMM assessment and RCM analyses discussed above. APSC verbally emphasized their concurrence to the benefits of these evaluations and agreed to cooperate and assist where possible. APSC formally agreed in a written *Memorandum of Agreement* (MOA), signed January 9, 2001, to support the implementation of the AMM and RCM analyses. Attachment (1) provides a copy of this MOA.

Additionally, as part of APSC efforts on Grant/Lease renewal, which they refer to as "Systems Renewal", APSC is enhancing its management system and many of their business processes, inclusive of elements of the maintenance process, to more effectively prioritize corrective actions for continued safe and reliable operation of TAPS. APSC has embraced the concept of knowing the operating requirements and understanding the potential risks and consequences of failure as an effective tool for identifying and prioritizing maintenance activities. The current APSC effort to improve the integration of its management system and the efficiency and effectiveness of specific business processes such as budgeting, maintenance, engineering, and project management should ensure the results are monitored and the processes themselves are improved over the long haul. Portions of this management system enhancement effort are summarized in a JPO/APSC Memorandum of Agreement (MOA), signed March 6, 2002. Attachment (9) provides a copy of this MOA.

4.0 Methodology/Scope

This part of the report describes the maintenance strategy formulation technique the JPO decided to use to evaluate the maintenance requirements of select TAPS systems. The following sections of the report describe the importance of developing the right maintenance strategies in light of the business as a whole and the maintenance management system.

4.1 A Maintenance Management Model

The following is presented to provide an overview of the basic elements of a modern day asset maintenance program. APSCs corporate Maintenance Manual, MP-167, governs implementation of the elements of this model.

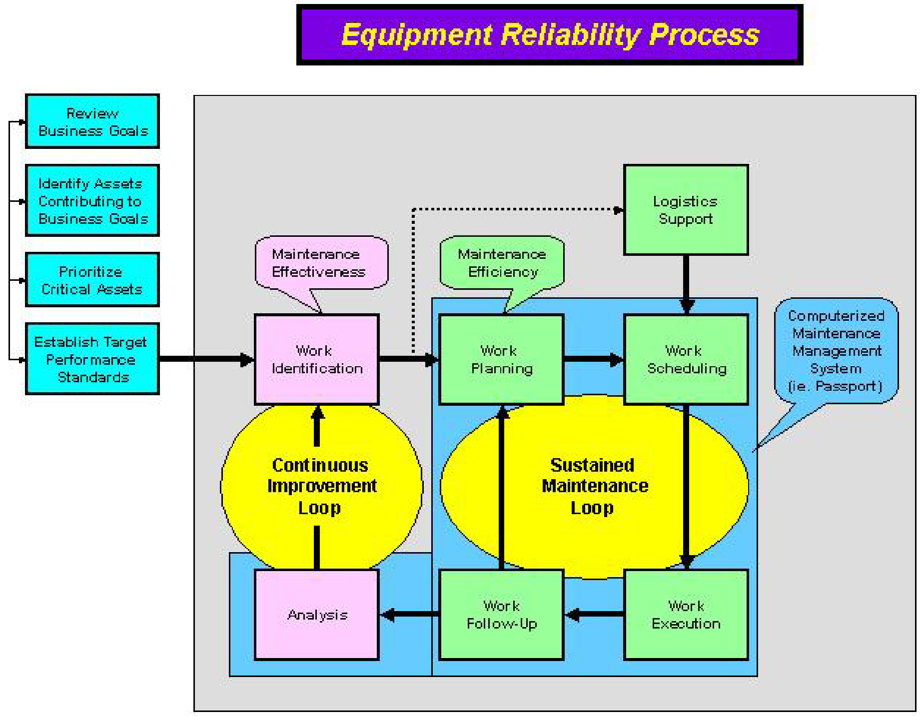
Maintenance only exists because the laws of physics tell us that any physical assets exposed to the real world will deteriorate. Why do we have physical assets? The answer lies in the fact that every physical asset is put into service because someone wants it to do something. In other words, it is expected to fulfill a specific function or functions. So it follows that assets are maintained in order to preserve the necessary function or functions. It is important to note that the emphasis is on preserving what the asset *does* not what it *is*.

Ultimately the focus is on meeting customer needs. Customer expectations are normally defined in terms of product quality, on-time delivery, competitive pricing, safety, and complying with environmental standards. By reviewing the composite requirements of all customers, the performance requirements of physical assets can be defined. Equipment performance parameters can be associated with quality, availability cost/unit, safety, and environmental integrity. To achieve this performance there are three inputs to be managed.

The first requirement is *Process Technology*. Process Technology provides capable equipment "by design" (inherent capability), to meet the equipment performance requirements.

The second requirement is *Operating Practices* that make use of the inherent capability of equipment. The documentation of standard operating practices assures the consistent and correct operation of equipment to maximize performance.

The third requirement is *Maintenance Practices* that maintain the inherent capability of the equipment. Deterioration begins to take place as soon as equipment is commissioned. In addition to normal wear and deterioration, other failures may also occur. This happens when equipment is pushed beyond its design limitations or operational errors occur. Degradation in equipment condition results in reduced equipment capability. Equipment downtime, quality problems, or the potential for accidents and/or environmental excursions are the visible outcome. It is necessary to manage the business processes to prevent such problems, and one of the business processes is maintenance of physical asset reliability. The Equipment Reliability Process to be discussed here is shown in the Figure below:



The Planned Maintenance Process, represented by the series of seven (7) elements on the right of the model aims to deliver targeted performance. Each element within the Maintenance process is in itself a sub process. A brief description of each of the seven elements follows:

1. *Work Identification*, as a process, produces technically based Equipment Maintenance Programs. Program activities identify and control failure modes impacting the equipment's ability to perform the intended function at the required performance level. Evaluation of activities is based on the consequences of failure.

2. *Planning* develops procedures and work orders for specific work activities. The procedures identify resource requirements, safety precautions and special work instructions required to execute the work.

3. *Scheduling* evaluates the availability of all resources required for work "due" in a specified time frame. Often this work requires the equipment to be shut down. A review of production schedules is required. Resources are attached to a specific work schedule.

4. *Logistic Support* looks at optimizing the minimum and maximum levels required for materials (stock and non-stock items), without impacting asset availability. Availability of skilled labor, tools, equipment and financial resources, etc.

5. The *Execution* process assures that trained and competent personnel do the required work.

6. The *Follow-up* process responds to information collected in the execution process. Work order completion comments outline what was done and what was found. Actual time and manpower, to complete the job, is documented. Job status is updated as complete or incomplete. Corrective work requests, resulting from the analysis of inspection data, are created. Requests are made for changes to drawings and procedures.

7. The process of *Analysis* evaluates maintenance program effectiveness. Gaps between actual process performance and the required performance are identified. Historical maintenance data is compared to the current process performance. Maintenance activity costs are reviewed. Significant performance gaps are addressed by revisiting the Work Identification function.

Each element is necessary for an effective maintenance strategy. Omitting any element could result in poor equipment performance, increased maintenance costs, or both.

For example, *Work Identification* systematically identifies the *right* work to be performed at the *right* time. Without proper *Work Identification*, maintenance resources may be wasted and unnecessary or incorrect work will be scheduled. Once executed, this work may not achieve the desired performance results, despite significant maintenance costs.

The *Planned Maintenance Process* is a cycle. Maintenance work is targeted to achieve required asset performance. Its effectiveness is reviewed and improvement opportunities identified. This guarantees continuous improvement in process performance impacted by maintenance.

Within the *Planned Maintenance Process* two internal loops exist: (1) *Planning*, *Scheduling*, *Execution* and *Follow Up*; and (2) *Work Identification* and *Analysis*.

Planning, *Scheduling*, *Execution* and *Follow Up*: Once maintenance activities are identified, equipment maintenance, based on current knowledge and requirements, is initiated. The selected maintenance activities will be conducted at the designed frequency and the process becomes self-sustaining.

Work Identification and *Analysis*: The continuous improvement loop. Performance gaps are identified, the root cause of these gaps are established, and corrective action recommended. The criteria for defining the maintenance activities, established in the *Work Identification* process, is revisited using updated information.

One approach to work identification is a structured methodology termed Reliability Centered Maintenance (RCM)

RCM is a highly prescriptive process used to identify the maintenance requirements of physical assets to ensure operational safety, environmental integrity and functional reliability. The RCM process involves the asset operators, maintainers, and responsible engineering resources in a comprehensive and interactive manner. RCM is currently considered by maintenance professionals to be a best practice in terms of identifying maintenance strategies for physical assets.

4.2 Asset Maintenance Management assessment

The JPO 1999/2000 Maintenance CMP report introduced the intent to conduct an Asset Maintenance Management assessment (AMM) on TAPS. There are many variations of maintenance management within the oil and gas industry; however, there are relatively consistent programmatic elements throughout. These are as follows:

- Management Leadership
- Maintenance, Engineering & Operations Organizational Structures
- Roles and Responsibilities
- Documentation Management
- Maintenance Planning
- Logistical Support
- Resource Management
- Computerized Maintenance Management System
- Maintenance Management Metrics
- Materials Management Metrics
- Root Cause Failure Analysis Process
- Maintenance Budgets

With the APSC Systems Renewal efforts underway (discussed in section 3.4 above), JPO did not conduct a formal AMM assessment, but alternatively, will monitor implementation of the RCM results; which inherently monitors maintenance management. Successful implementation of the RCM results requires structured execution of these elements; failure to consistently implement the RCM results, may indicate a breakdown within these programmatic elements. Section *5.2 RCM Results Implementation* provides a discussion of implementation oversight.

4.3 RCM and TAPS Systems Oversight

The JPO has established a "systems-based" approach to the oversight of TAPS maintenance. This was conceived to provide a disciplined oversight strategy, which specifically identifies the physical systems and sub-systems that comprise

TAPS, the associated user functions with the associated performance standards, and the method of function preservation for safe operations. As such, the current JPO maintenance oversight efforts have been designed to assess the maintenance requirements of particular TAPS systems and sub-systems, the adequacy of systems and sub-system monitoring for potential functional failures, and the effectiveness of transitioning monitoring results into corrective maintenance work activities. A maintenance strategy formulation technique called *Reliability Centered Maintenance* (RCM) has been used to facilitate this effort.

The RCM methodology JPO applied, complies with the American National Standard, *SAE JA1011 - Evaluation Criteria for Reliability-Centered Maintenance (RCM) Processes*. A copy of *SAE JA1011* is provided as attachment (2) to this report. Also, attachment (3) provides a copy of *SAE JA1012 - A Guide to the Reliability-Centered Maintenance (RCM) Standard*, which supplements *SAE JA1011* by providing terminology definitions. The following provides a summary of this RCM process (see attachments (2) and (3) for further detail).

RCM can be defined as 'a process used to determine what must be done to ensure that any physical asset continues to do whatever its users want it to do in its present operating context'. The RCM process entails asking seven questions about the asset or system under review, as follows:

- What are the functions and associated performance standards of the asset in its present operating context (*functions*)?
- In what ways does it fail to fulfill its functions (*functional failures*)?
- What causes each functional failure (*failure modes*)?
- What physically happens when each failure occurs (*failure effects*)?
- In what way does each failure matter (*failure consequences*)?
- What can be done to predict or prevent each failure (*proactive tasks and task intervals*)?
- What should be done if a suitable proactive task cannot be found (*default actions*)?

The following provides a brief description of how each of these questions are applied in the RCM analysis:

The *first step* in the RCM analysis is to describe the present *operating context* of the asset under review and thereafter define the *functions* of each asset in its operating context, together with its associated desired standards of performance. During this part of the process the inherent (design) capability of the asset is checked to make sure the asset is physically capable of meeting the user's desired standard of performance.

Note: The functions and associated desired standards of performance, failure modes and effects, failure consequences, and failure management polices that apply to technically identical assets can vary widely if their operating context varies. So the operating context is defined clearly right at the start of the RCM process. The operating context includes a description of the overall process in which the asset is being used, the part played by the asset in that process, and its relevance to/impact on the business as a whole.

The objectives of maintenance are defined by the functions and performance expectations of the asset under review. But how does maintenance achieve these objectives? The only occurrence that is likely to stop any asset performing to the expectations of the user is some kind of failure. This means maintenance achieves its objectives by managing failure. However, before we can apply a suitable maintenance task we need to know what failures can occur. The RCM process does this on two levels:

- By identifying what circumstances amount to a failed state
- Then by asking what events cause the asset to get into a failed state.

Therefore, the *second step* in the RCM process is to identify the failed states, which can be defined as the inability of the asset to meet desired standards of performance, these are known in RCM terms as *functional failures*.

The *third step* in the RCM process is to identify the events that cause the asset to get into a failed state, known as *failure modes*. All "reasonably likely" failure modes are considered, these include (1) those that have occurred on the same or similar equipment operating in the same context, (2) failures which are currently being prevented by existing maintenance programs, and (3) failures that have not happened yet but could under the operating context under consideration. Failure mode considerations include normal wear and tear or deterioration, failures caused by human error, design flaws, etc. so that all reasonably likely causes of equipment failure can be identified and dealt with appropriately.

The *fourth step* in the RCM review process is to describe what physically happens each time failure mode occurs. These are known as *failure effects*. The effects are described in enough detail to enable review groups to assess failure consequences. The following information should be recorded:

- What evidence (if any) that the failure has occurred?
- In what ways (if any) could it affect safety or the environment?
- In what ways (if any) does it affect operations?
- Does it cause any secondary damage?
- What must be done to repair it?

Note: One of the objectives of the RCM analysis is to establish whether proactive maintenance is necessary. Therefore we cannot assume that some sort of proactive maintenance is being done already, so the effects of a failure should be described as though nothing is done to prevent the failure mode.

The *fifth step* in the RCM process involves application of a highly structured consequence evaluation and policy selection algorithm to each failure mode. Through this decision algorithm, the *failure consequence* for each failure mode is categorized into one of the following failure consequence categories:

- *Hidden failure consequences:* Hidden failures have no direct impact (i.e. their failure remains unknown until another failure occurs), but they expose the organization to serious, often catastrophic consequences in the event of the multiple failure.

- *Safety and environmental consequences:* A failure has safety consequences if it could injure or kill someone. It has environmental consequences if it could breach a corporate, regional, national or international environmental standard.

- *Operational consequences:* A failure has operational consequences if it affects operations (output, product quality, customer service or operating costs in addition to the direct cost of repair)

- *Non-operational consequences:* Evident failures that fall into this category affect neither safety nor production, so they involve only the direct cost of repair.

The *sixth step* in the RCM process continues with application of the decision algorithm, incorporating precise and easily understood criteria for deciding which (if any) *proactive tasks and task intervals* is technically feasible in any context and what resource type should complete the task. It also incorporates criteria for deciding whether any task is worth doing, a decision, which is governed by how well, the candidate task deals with the consequences of the failure.

Finally, the *seventh step* determines if a proactive task cannot be found that is both technically feasible and worth doing, the decision algorithm leads users to the most suitable *default actions*.

In some situations a suitable failure management policy cannot be identified for a particular failure mode where the consequences of the failure affect safety or the environment. In these situations, the default decision is "redesign is compulsory". Compulsory redesign recommendations fall into four categories: (1) modifications to hardware; (2) modifications to procedures; (3) modifications to training; and (4) no action required, as long as the risk is considered tolerable.

RCM stresses the need to involve personnel in the field, especially operations personnel, in the maintenance strategy formulation process. This is because maintenance personnel simply cannot answer all these questions on their own. Many of the answers can only be supplied by production or operations personnel. This applies especially to questions about functions, desired performance, failure effects and failure consequences.

An RCM analysis results in three tangible outcomes, as follows:

- Schedules to be done by the maintenance department
- Revised operating procedures for the operators of the asset
- A list of areas where changes must be made to the design of the asset or the way in which it is operated to deal with situations where the asset cannot deliver the desired performance in its current configuration.

The JPO is most concerned with and will track (1) implementation of those tasks identified to address failure modes where the consequences of failure are classified as hidden, safety, or environmental, and (2) resolution of the compulsory redesign recommendations.

Attachments (4) provides the reports that describe the RCM tasks identified to date that JPO intends to track at the Valdez Marine Terminal. Attachments (5) provides the reports that describe the RCM tasks identified to date that JPO intends to track on the pipeline.

In order to provide an initial estimate of the scope of the TAPS RCM analyses, JPO reviewed the TAPS sub-systems described in the *TAPS Design Basis Update Manual*, DB-180[3], and conducted a qualitative evaluation to determine the "complex systems[4]" considered most critical to public safety, environmental protection, and pipeline integrity[5].

From this initial scoping review, the following complex (critical) systems of TAPS were initially considered for RCM analyses:

Valdez Marine Terminal

- ➢ Back Pressure Control ☑
- ➢ Pressure Relief ☑
- ➢ Ballast Water Treatment (BWT) ☑
- ➢ Control System (Operations Control Center)
- ➢ Leak Detection System ☑
- ➢ Fire Protection System ◈
- ➢ Combustible Gas Detection ◈
- ➢ Hazardous Gas Detection ◈
- ➢ Tanks ◈

[3] "Design Basis" is defined as the scientific and engineering principles upon which system designs are founded

[4] Complex systems are comprised of many sub-systems necessary to the functionality of the larger more "complex" system. It may take several RCM analyses to completely analyze a complex system.

[5] The complex systems of TAPS have also been referred to as the "critical" systems of TAPS. The term critical is not necessarily appropriate nomenclature as its definition is subject to interpretation, but it has become commonplace nonetheless and is used interchangeably with complex.

Pipeline

- ➢ TAPS Backbone Communication
- ➢ TAPS Block Valve Communication
- ➢ Mainline Pipe (Buried & Aboveground) ☑
  - Pipe Support ☑
  - Special Bury Sites (Refrigeration) ☑
- ➢ Mainline Valves
  - ✧ Check Valves ⊡
  - ✧ Manual Gate Valves ◈
  - ✧ Remote Gate Valves (RGV's) ⊡

Pump Stations

- ➢ Mainline Pressure Relief ☑
- ➢ Mainline Valves ◈
- ➢ Tanks ☑
- ➢ Control System
- ➢ Leak Detection System (LEFMs) ☑
- ➢ Combustible Gas Detection ☑
- ➢ Hazardous Gas Detection ☑
- ➢ Fire Protection System ☑

Note: Those complex systems identified with a "☑" have received an RCM analysis to date. Those systems marked with a "⊡" are scheduled for evaluation summer 2002. Those systems marked with a "◈" have been scheduled by APSC under a four year maintenance strategy evaluation plan.

It should be noted that successful implementation of an RCM-based maintenance management strategy requires that the process be continuous, not a singular project. Complete RCM analysis of all the complex systems of TAPS (inclusive of effective implementation) could conceivably take several years. JPO will require APSC to continue to improve its maintenance program to provide standard business practices, which continue to deliver a structured, disciplined, and documented approach to asset maintenance. JPO will continue to evaluate APSC maintenance management practices throughout the term of the Grant or Lease renewal.

For the purposes of TAPS Grant/Lease Right-of-Way renewals, JPO has completed a number of RCM analyses to provide a basis for quantitatively evaluating the APSC commitment to long-term maintenance of TAPS.

To further refine the scope of the TAPS RCM analyses and establish a starting point, JPO conducted a series of qualitative risk analyses utilizing TAPS sub-system experts. These risk analyses were qualitative and based on decisions made by the TAPS sub-system experts. The perceived higher risk sub-systems were those sub-systems whose functional failures might have the greatest impact on public safety, protection of the environment, or integrity of the pipeline. Implementation of an RCM based maintenance management strategy is a process. JPO conducted these qualitative criticality analyses only to provide a foundation from which to start the seeds of an RCM based maintenance management program. The sub-systems thus far analyzed were derived in part from this criticality analysis.

4.4 GRANT/LEASE COMPLIANCE ISSUES

The JPO CMP report, *Examining Grant & Lease Compliance*[6], discusses unresolved issues related to the TAPS aboveground pipe and associated support structures. Resolution of these issues was deferred to the TAPS RCM analyses. The following summarizes these issues:

4.4.1 Slope Stability

Stipulation 3.5, *Slope Stability,* requires that if unstable slopes cannot be avoided, the pipeline must be protected from potential ground movement. Stipulation 3.9, *Construction and Operation,* requires that degradation of permafrost shall not jeopardize pipeline foundations. One half of the pipeline (approximately 400 miles) is built above ground, on thaw unstable soil. There are numerous slopes consisting of unstable soils, some with a potential for soil liquefaction. Thus, wherever thawing has taken place in areas with thaw unstable soils, the potential to jeopardize pipeline foundations exists. Examples of this condition are on the Klutina Hill, where thawing was arrested through the use of additional insulation with wood chips, and on the Squirrel Creek slopes, which experienced general ground thawing.

JPO conducted assessments on compliance to Stipulation 3.5, *Slope Stability* and Stipulation 3.9, *Construction and Operations*; both of these assessments concluded that thawing of warm permafrost south of the Brooks Range could potentially present a threat to the stability of the above ground pipe support system. Long-term monitoring with defined criteria for intervention was recommended and resolution was deferred to a RCM analysis scheduled for the above ground pipe. See section *5.3* G*rant/Lease Compliance Issues* for the results of the RCM analysis.

4.4.2 Fault Crossings

Stipulation 3.4.2 *Fault Displacements* includes requirements for fault crossings. Examination of the pipeline right-of-way found no new construction in the three designated fault zones. After reviewing the available fault crossing design documentation, JPO determined that it was not fully explanatory and requested that APSC clarify and validate the original fault crossing design. APSC provided

[6] Examining Grant & Lease Compliance – Trans-Alaska Pipeline System, Joint Pipeline Office Comprehensive Monitoring Program Report #11, April 2002

a *Fault Crossing Design Assessment Final Report*, prepared by Michael Baker Jr., Inc., Feb. 8, 2002. The report shows that the modeling of the pipeline movement in response to maximum fault displacement is consistent with the original design analysis. There were three pipe support beams (bents) at the Denali Fault where the pipe displaced slightly beyond the limits of the cross beams at the full design temperature. The Denali Fault Crossing issue has been incorporated into the aboveground pipe RCM analysis. See section *5.3 Grant/Lease Compliance Issues* for the results of that analysis.

4.4.3 Pipeline Movement (Hydraulic Events)

There were two incidents of hydraulically caused pipe movement included in the JPO report *Examining Grant & Lease Compliance*: (1) Milepost 170 and (2) Check Valve 50. The Milepost 170 incident was extensively discussed in the 1999/2000 Operations CMP[7]. During response operations related to the Milepost 400 bullet hole spill, it was discovered that mainline Check Valve 50 and several pipeline shoes had moved and nine adjacent anchors had been tripped. Contrary to the Milepost 170 incident, the above ground pipeline support system performed as designed leaving the pipeline fully supported with some remaining energy relief capability.

JPO oversight of these two incidents raised questions and JPO findings related to the adequacy of the APSC surveillance and maintenance program and their applicability to arctic and subarctic conditions. APSC and JPO agreed to address these issues in the RCM analyses of the mainline valves (remote gate valves and check valves) scheduled for summer 2002.

4.5 JPO DATABASE MANAGEMENT SYSTEM (DBMS)

JPO oversight of the TAPS is an ongoing and highly dynamic effort, which incorporates numerous work activities conducted by the many agencies that comprise the JPO. Tracking, trending, and reporting on the multitude of oversight issues is a necessary function of the office. To accomplish this function, JPO has developed a Database Management System (DBMS), which provides for capturing the various JPO oversight efforts in a comprehensive and quantitative manner. The issues presented in this report, as well as the associated on-going efforts to address resolution of all identified deficiencies, are cataloged and tracked through the use of this DBMS. The DBMS provides JPO with the ability to review TAPS deficiencies in a sub-system specific manner.

The architecture of the DBMS can best be illustrated by a three-dimensional (3-D) model of the JPO TAPS oversight program. The following diagram provides a representation of this model.

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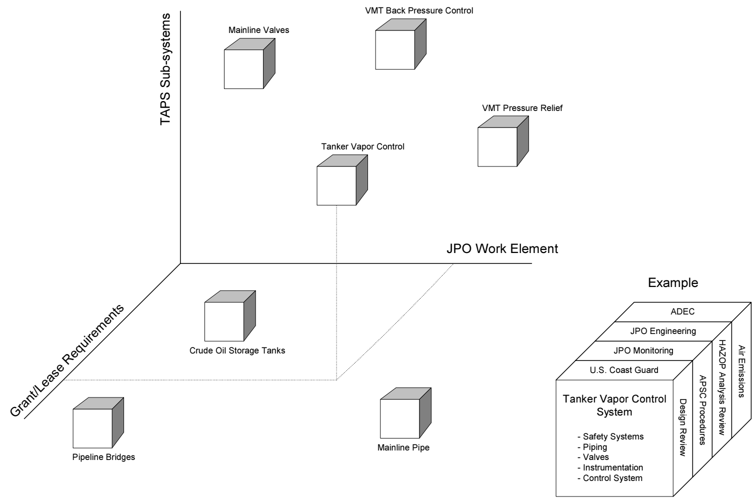
[7] Joint Pipeline Office Comprehensive Monitoring Program Report: TAPS Operations, January 1999 – July 2000, published January 2001.

JPO TAPS Oversight Program



The three principle elements of this model are (1) the requirements of the Grant/Lease Rights-of-Way; (2) the JPO organization and associated work programs; and (3) the physical sub-systems that comprise TAPS.

The cubical example is intended to represent how the DBMS catalogs the work conducted on the TAPS Tanker Vapor Control System, by the various JPO agencies, in accord with their respective Grant/Lease authorities.

The U.S. Department of the Interior, Office of Inspector General (OIG), reviewed the DBMS concept in its 2001 survey of JPO oversight of TAPS[8]. The IG recommended that JPO "Complete implementation of the comprehensive monitoring Program database to ensure effective monitoring of TAPS before the Agreement and Grant of Right-of-Way is reviewed".

The DBMS has been used to facilitate compilation of JPO oversight information in support of Grant/Lease compliance evaluations as reported in the JPO CMP report *Examining Grant & Lease Compliance – Trans-Alaska Pipeline System*.

The reports resulting from the TAPS RCM analyses are cataloged within the DBMS, as is the assigned follow-up work associated with tracking implementation of associated maintenance tasks. Continuous improvement of this computer tool is a core administrative effort within JPO.

[8] Survey Report - Oversight Activities of the Trans-Alaska Pipeline System, Bureau of Land Management, Report No. 01-I-206, U.S. Department of Interior, Office of Inspector General

5.0 Results and Discussion

The TAPS RCM analyses identify and document the relationship between equipment maintenance strategies and the preservation of associated sub-system functions. As such, these analyses enhance the maintenance practices employed by APSC on specific TAPS sub-systems. The result of an RCM analysis is a list of actions to be performed to prevent the system from failing to perform its desired functions and to manage the consequences of failures that cannot be prevented. There are two programmatic elements necessary to successfully perform asset maintenance management using the RCM methodology: (1) conducting the RCM analyses; and (2) implementing the results (maintenance tasks) of the analyses. Conducting the RCM analyses is discussed in section *4.3 RCM and TAPS Systems Oversight* above. The following sections discuss the results of the RCM analyses, and JPO verification of implementation of the associated tasks:

5.1 RCM Analyses:

The following sections provide the results of the RCM analyses conducted to date. Attachment (4) provides the reports that describe the RCM tasks that JPO intends to track at the Valdez Marine Terminal. Attachment (5) provides the reports that describe the RCM tasks that JPO intends to track for the pipeline.

Detailed reports for each RCM analysis are maintained by JPO and APSC. The contents of these reports typically include the following:

- Executive Summary
- Introduction to Reliability-Centered Maintenance
- System Operating Context
- Applicable Drawings (typically Piping and Instrumentation Drawings)
- Detailed Pictures
- Information Worksheets
- Decision Worksheets
- Failure Mode Details
- Work Packages
- Failures Recommending Redesign
- Failures Requiring Compulsory Redesign
- Hidden, Safety and Environmental Tasks
- Review Group Recommendations

5.1.1 Valdez Marine Terminal

The Valdez Marine Terminal (VMT) is the southern terminus of the Trans-Alaska Pipeline System (TAPS), which carries crude oil from Prudhoe Bay to the ice free port of Valdez. The port of Valdez is located at the northeastern end of Prince William Sound. The site occupies approximately 1,000 acres of private ownership on the southern shore of the port, extending from near sea level to 538 feet in elevation at the west tank farm.

The primary functions of VMT include Operations Control Center (OCC) for the pipeline, receipt, metering and storage of crude oil, and the transfer of crude oil to ocean going tankers for transport to U.S. markets. This includes: eighteen storage tanks totaling 9.18 million barrels in capacity, tanker loading facilities for up to 100,000 barrels per hour, three berths for loading tankers, two of which are equipped with vapor collection systems.

The major support systems for VMT include crude oil metering, vapor control, ballast water handling and treatment, power generation, other utility systems, facilities for maintenance, security, materials receiving and control, emergency response, tanker escort and harbor facilities for support vessels.

The Valdez Marine Terminal (VMT) has applied the Reliability-Centered Maintenance (RCM) process to various physical assets since 1997.

The table below provides the status of TAPS sub-systems analyzed at the VMT using the RCM process. Data totaling the functions, functional failures, and failure modes from each completed analysis is provided:

Trans-Alaska Pipeline System RCM Analyses – Valdez

Complex System	Critical Sub-System	System/Equipment	Status	Analysis Results		
				Functions	Functional Failures	Failure Modes
		Ballast Water Treatment				
➢		Biological Treatment System				
	✓	Biological Treatment Tanks	Completed	36	41	90
	✓	BETX Analyzer	Completed	27	33	76
	✓	Gravity Separation Tanks	Completed	46	69	192
	✓	Separation Tank Cathodic Protection System	Completed	1	3	13
		Power Vapor				
➢	✓	Vapor Recovery System				
	✓	Swing Compressor 2B	Completed	84	107	469
	✓	Swing Compressor Lube Oil System	Completed	66	103	166
	✓	Tanker Vapor Recovery System				
	✓	Berth Compressor 2A	Completed	45	64	160
	✓	Storage Tank Vapor System				
	✓	Tank Farm Compressor 2C	Completed	78	100	291
	✓	Nitrogen Purge System				
	✓	Nitrogen Skid	Completed	48	52	80
	✓	Compressed Air System	Completed	67	71	143
	✓	Waste Gas Incineration System				
	✓	Waste Gas Incinerators 1, 2, & 3	Completed	111	135	339
	✓	Inert Gas System				
	✓	Inert Gas Cooler	Completed	23	29	82
		Marine Operations				
➢		Berth Loading Arms (Berths 3, 4, 5)				
	✓	Loading Arms	Revisit Original	21	25	166
	✓	Chicksan Hydraulic Skid	Revisit Original	19	26	75
➢		Tanker Vapor Collection System (Berths 4 & 5)				
	✓	Vapor Collection Arms 5 & 6	Revisit Original	39	44	149
	✓	Oxygen Analyzers	Revisit Original	33	37	72
	✓	Vapor Collection Control	Revisit Original	58	54	132
	✓	Fenwall System	Completed	51	63	136
➢		Berth Fire System				
	✓	Firewater Pump	Revisit Original	30	31	47
	✓	Foam Concentrate Skid	Revisit Original	35	39	48
	✓	Berth Instrument Air Compressor	Revisit Original	56	87	161
		Oil Movements				
➢	✓	Back Pressure Control System	Completed	29	44	101
➢	✓	Terminal Pressure Relief System	Completed	28	32	86

Those systems with a “Revisit Original” status have already received an RCM analysis and APSC has scheduled a follow-up review as part of their continuous improvement process. The following sections describe an abbreviated operating context of each system analyzed. Attachment (4) provides specific task descriptions associated with each failure management decisions for failure modes identified as having hidden, safety, or environmental consequences. Attachment (6) provides Task Breakdown diagrams showing the number of identified tasks associated with each failure consequence type (i.e. hidden, safety, environmental, operational, and non-operational):

5.1.1.1 Ballast Water Treatment (BWT)

The BWT facility is a self-contained plant for the processing of oil contaminated waters. Although it is primarily designed to treat the ballast waters of incoming tankers, it also processes water from oily sumps, oily streams, industrial wastewater sewer system, and oil spill waters at the Valdez Martine Terminal. In addition, condensate from the Terminal's vapor recovery system and gray water from the BWT Control Building are treated by this system.

To protect the quality of water in Port Valdez, oily ballast water is pumped from the tankers into onshore storage tanks for processing by the BWT facility. Tankers with clean segregated ballast tanks may discharge non-oily ballast directly to port.

After being pumped from a ship, the contaminated ballast is permitted to settle for a minimum of 4 hours in the ballast storage tanks. Oil which rises during that time is skimmed and pumped to the oil recovery section of the treatment plant and back to tankers or the terminal crude storage tanks.

The remaining water is passed through a chemically aided, dissolved air flotation treatment unit until the water can be discharged with less than 8 parts of oil per million to holding ponds. The cleansed water is dispersed from holding ponds through jet orifices into the sea at a point about 300 feet below sea level.

The BWT facility has completed the following four analyses with several additional analyses scheduled for 2002 and 2003:

- Biological Treatment Tanks
- BETX Analyzer
- Gravity Separation Tank
- Gravity Separation Tank Cathodic Protection System

Biological Treatment Tanks
Biological treatment of BETX (Benzene, Ethylbenzene, Toluene, Xylene) is the fourth phase of water treatment. Nutrient enriched water from the Dissolved Air Floatation (DAF) cells enters the Biological Treatment Tanks (BTTs) through the splitter box. Influent diffusers release the water evenly across the head of each tank. BTTs provide the space and time needed to promote biological oxidation of oils remaining in the water. Two tanks, Tank 74 (west tank) and Tank 75 (east tank), are identical and work in parallel. Each tank's total capacity is 5.5 million gallons. As the water travels down the tanks, it is mixed and aerated to promote optimum conditions for the biological oxidation of any remaining oils. After an average of 16 hours in a BTT, the water spills under the weir then through slide gates into weir troughs. Overflowing these troughs, the water falls through a drop

box into the effluent channel. The effluent channel leads to a sluice gate, where BTT water is released to the Fan/Meter Building and Port Valdez.

The RCM analysis identified 36 functions, 41 functional failures and 90 failure modes and their respective failure effects.

BETX Analyzer

The BETX (Benzene, Ethylbenzene, Toluene, Xylenes) analyzer is a leading indicator of the volatile hydrocarbons in the process water at the biological treatment tanks. The BETX analyzer receives samples of the waters from the biological treatment tanks 58-TK-74 and 58-TK-75 and determines the total concentration of BETX present. The results of the BETX analyzer are comparable to the results obtained by laboratory testing in accordance with EPA Method 602. This information is displayed on the control screens at the BWT control room. This display permits the BWT control room operator to make knowledgeable decisions on the process controls of the ballast water treatment facility so as to ensure that effluent waters are within Federal and State permit levels of BETX. . The BETX analyzer is also used as an indicator of process efficiency. As with all biological systems there are subtle but important indicators of potential, process upsets due to a variety of physical or chemical influences. Operational feedback devices such as the BETX analyzer are used to make assessments and, ultimately, predictions of process efficiencies. The on-line BETX analyzer is used in conjunction with flow, temperature, dissolved oxygen and other parameters to properly operate the treatment process. The BETX analyzer is required to be capable of taking and processing at least one sample every 25 minutes.

The RCM analysis identified 27 functions, 33 functional failures and 74 failure modes and their respective failure effects.

Gravity Separation Tanks

The three 90s tanks, also called ballast water storage tanks receive water and hold it in a quiescent state to allow for gravitational separation. Standard settling time for a batch of ballast water is four hours. The Operations Control Center (OCC), at the direction of the BWT Technicians, controls the delivery of ballast water to the 90s tanks.

Each 90s tank is 250'in diameter and 53.5'high. Maximum process volume is approximately 430,000 barrels; maximum fill height is 49.7' to allow a slosh zone during earthquakes. When the tank reaches maximum volume or has received all ballast water from tankers at berths, the tank is closed and the settling process clock begins. Standard settle time is four hours. This time may be extended or reduced to a minimum of two hours if water quality is within limits. The decision to reduce settling time is usually prompted by space limitation in the 90s tanks during periods of high ballast water reception rates. After receiving its limit of ballast water, a tank is closed. The tank remains closed for the duration of its prescribed settling time. While in this mode, the tank is said to be settling; that is, undergoing gravitational separation of water, oil, and sediments. Settling creates three fluid layers:

- Oils (primarily north-slope crude oil that rises to the top).
- Emulsion water mixed with smaller oil particles, still in migration upward. (It sits between the oil and water layers.)
- Water (primarily clarified sea water), it remains at the bottom of the tank.

Clarified water is discharged from the 90s tanks to the DAF system. A polymer is added to the effluent that facilitates the flotation. Recovered oils are skimmed for transfer to the 80s tanks.

The RCM analysis identified 46 functions, 69 functional failures and 192 failure modes and their respective failure effects.

Gravity Separation Tank Cathodic Protection System
The RCM analysis identified 1 function, 3 functional failures and 13 failure modes and their respective failure effects.

5.1.1.2 Vapor Recovery System

Vapor Recovery Compressor Configuration
There are five gas compressors available for use in the Vapor Recovery System. Two of the compressors, 1C and 2A are dedicated to Berths 4 and 5, and two compressors, 2C and 2D, are dedicated to tank farm service. The remaining compressor 2B operates as a swing compressor between the tank and the berths. This has provided a backup source of gas compression in the event a dedicated compressor needs to be taken out of service for maintenance. As a tank farm compressor (also referred to as blanket gas compressors) it is used to raise the pressure of the gas recovered from the crude oil storage tanks from approximately 13.8 psia to 27.2 psia (12.5 psig). This combined gas with that recovered from vessel loading is used for vapor balancing of the crude oil storage tanks or is used as a fuel in the power plant boilers to reduce fuel oil consumption. Excess vapor, or waste gas, is destroyed in the waste gas incinerators. As a berth compressor it collects vapor from either berths 4 or 5 at approximately 14.9 psia, raises the pressure to approximately 27.2 psia (12.5 psig), and combines the gas with tank farm blanket gas. The combined gas is used for vapor balancing of the crude oil storage tanks or is used as a fuel in the power plant boilers to reduce fuel oil consumption.

Swing Compressor 2B
Compressor 2B suction and discharge piping is configured to allow 2B to operate in either the Tank Farm or Berth system as a swing compressor by selecting the appropriate valve line up through the Digital Control System (DCS). This has provided a backup source of gas compression in the event a dedicated compressor

needs to be taken out of service for maintenance. The compressor unit consists of a rotary, single stage compressor driven by an electric motor through a speed increasing gear. The swing compressor operates at 2,521 rpm. The compressor contains its own seal system and suction and discharge silencers. The swing compressor utilizes nitrogen as buffer gas to keep the seals clean. All components are mounted on a common skid within an acoustical enclosure. An external glycol cooling system supplies glycol to the compressor jackets. An external lube oil system supplies oil to the compressor, gear, and motor for cooling and lubrication. A local control panel is provided for monitoring and controlling compressor and lube oil equipment. Gas is provided to the compressor suction at 13.4 to 13.8 psia from the tank farm or from either Berths 4 or 5 at approximately 14.9 psia, and is compressed to approximately 27.2 psia (12.5 psig). In the process of compression, gas temperature is typically increased to approximately 200°F. On the discharge of the gas compressor is a dedicated gas cooler, whose function is to lower the high pressure (HP) gas temperature to approximately 100°F. Gas exits the HP end of the tank farm compressor and passes through the discharge silencer and check valve then through the north wall of the compressor enclosure, through the discharge valve, and up to the cooler inlet manifold located on the north side of the inert gas cooler. From the cooler inlet manifold, the gas passes through the cooler tubes to the cooler discharge manifold on the south side of the cooler. From the cooler discharge manifold the gas passes a cooler discharge block valve, then the line runs underneath the cooler to the north side and enters the HP header. Just downstream of the discharge check valve, an 8-inch line containing a rupture disk ties the discharge line back to the suction line. If a pressure differential of 45 psid, at normal operating temperature, occurs between the suction and discharge piping, the rupture disk will burst and allow gas to return from the discharge to the suction.

The RCM analysis identified 84 functions, 107 functional failures and 470 failure modes and their respective failure effects.

Swing Compressor Lube Oil System

The lube oil skid consists of a pump, a filter, a cooler, a reservoir and an accumulator. This system supplies lube oil to the compressor. The oil is supplied at a pressure of 30 psi, a flow rate of 63 gpm and a temperature of approximately 120°F. The pump is a stand alone rotary electric pump drawing 4 horsepower and rated to produce an output of 50 psig. It receives oil from the reservoir through a line fitted with a suction valve and Y-strainer, and normally pumps it through the cooler. The pump is fitted with a discharge check valve, an isolation valve and a pressure relief valve on the discharge side that is set to activate at 60 psig. This pressure relief valve is fitted with a manual bypass. This electric pump was originally installed as a backup to a steam-driven system, but has been running on its own for 20 years.

There are two coolers connected in a duty-standby arrangement situated downstream from the pump. A temperature gauge is also fitted here. There are two filters connected in a duty-standby arrangement fitted to the system downstream from the coolers. The filters are designed to remove particles of greater than 10 microns from the oil. The filters are fitted with a differential pressure alarm that sounds if the pressure across the duty filter exceeds 15 psig. Also connected here are switches for high and low oil temperature alarms that sound at 130°F and 100°F respectively on the compressor local control panel.

The accumulator holds 60 gallons of oil. If the compressor has to be shut down in the event of a failure of the lubrication system, the accumulator will supply oil for approximately one minute to allow the compressor to coast to a stop. The reservoir holds 600 gallons of oil. Oil is returned to the reservoir from the compressor by gravity, as the return line is provided with a continuous downward slope. The compressor is fitted with two low oil pressure switches, one sounds and alarm at 20 psig the other shuts down the compressor at 15 psig.

The RCM analysis identified 66 functions, 103 functional failures and 166 failure modes and their respective failure effects.

Berth Compressor 2A

The Berth Compressor rotates at 3,317 rpm increasing the flow capacity of the compressor to handle the vapor flow requirements of loading ships at 100,000 bbl/hr. It has a nitrogen seal buffer gas system and temperature and vibration monitoring. A third compressor, 2B, the berth/tank swing compressor is also available for berth service. This compressor has a design loading rate of approximately 80,000 bbl/hr. The selection of compressors is made on the DCS, which then automatically makes the appropriate valve line-up logic and ties the proper control and shutdown logic between the selected compressor and the respective berth.

The compressor unit consists of a rotary, single stage compressor driven by an electric motor through a speed increasing gear. All components are mounted on a common skid within an acoustical enclosure. An external glycol cooling system supplies glycol to the compressor jackets. An external lube oil system supplies oil to the compressor, gear, and motor for cooling and lubrication. A local control panel is provided for monitoring and controlling compressor and lube oil equipment. The Berth compressor collects vapor from either Berths 4 or 5 at approximately 14.9 psia, raises the pressure to approximately 27.2 psia (12.5 psig), and combines the gas with tank farm blanket gas. In the process of compression, gas temperature is typically increased to approximately 200°F. On the discharge of the gas compressor is a dedicated gas cooler, whose function is to lower the HP gas temperature to approximately 100°F. Gas exits the HP end of the compressor and passes through the discharge silencer and check valve then through the north wall of the compressor enclosure, through the discharge valve, and up to the cooler inlet manifold located on the north side of the inert gas cooler. From the cooler inlet manifold, the gas passes through the cooler tubes to the cooler discharge manifold on the south side of the cooler. From the cooler discharge manifold the gas passes a cooler discharge block valve, then the line runs underneath the cooler to the north side and enters the HP header.

The RCM analysis identified 45 functions, 64 functional failures and 160 failure modes and their respective failure effects.

Tank Farm Compressor 2C

There are two dedicated compressors, 2C and 2D, and one tank/berth swing compressor, 2B, available for tank farm service. The compressors are manifolded in parallel and are started and stopped from the DCS control screen to move gas as required. The HP gas header also routes excess gas to the incinerators and power boilers.

The compressor unit consists of a rotary, single stage compressor driven by an electric motor through a speed increasing gear. The compressor operates at 2,521 rpm. The compressor contains its own nitrogen seal system and suction and discharge silencers. All components are mounted on a common skid within an acoustical enclosure. An external glycol cooling system supplies glycol to the compressor jackets. An external lube oil system supplies oil to the compressor, gear, and motor for cooling and lubrication. A local control panel is provided for monitoring and controlling compressor and lube oil equipment.

Gas is provided to the tank farm compressor suction at 13.4 to 13.8 psia and is compressed to approximately 27.2 psia (12.5 psig). In the process of compression, gas temperature is typically increased to approximately 200°F. On the discharge of the gas compressor is a dedicated gas cooler, whose function is to lower the HP gas temperature to approximately 100°F. Gas exits the HP end of the tank farm compressor and passes through the discharge silencer and check valve then through the north wall of the compressor enclosure, through the discharge valve, and up to the cooler inlet manifold located on the north side of the inert gas cooler. From the cooler inlet manifold, the gas passes through the cooler tubes to the cooler discharge manifold on the south side of the cooler. From the cooler discharge manifold the gas passes a cooler discharge block valve, then the line runs underneath the cooler to the north side and enters the HP header.

The RCM analysis identified 78 functions, 100 functional failures and 291 failure modes and their respective failure effects.

Nitrogen Purge System

Nitrogen is generated to provide a clean, inert gas to the seals of the berth and swing vapor compressors for the tanker vapor collection system. Nitrogen is also used as a medium to maintain velocity in the incinerator waste gas burners during cycling of flow control valves to ensure flashback protection and as a pressurizing gas for the tanker vapor collection piping between tanker loading. Nitrogen is also available for purging of the oxygen from vapor collection lines prior to startup or to recover from process upsets and to maintain pressure in the tanker vapor collection system between tanker loading.

The RCM analysis identified 48 functions, 52 functional failures and 80 failure modes and their respective failure effects.

Waste Gas Incinerator

There are three waste gas incinerators of which two are online to burn excess waste gas. The third incinerator is normally on standby. Each incinerator comprises of four burners located at 90° increments around the outside of the incinerator so the flame of one burner is opposed by the flame of another burner. Each burner is equipped with a propane pilot torch for lighting the main gun, a steam atomized oil gun, a three-stage waste gas burner, and flame scanners to detect the presence of a flame at the burner. Each burner has a dedicated fuel oil combustion air blower and a waste gas combustion air blower. A single quench air blower supplies cooling air to each incinerator. This analysis resulted in substantial financial savings.

The RCM analysis identified 111 functions, 135 functional failures and 339 failure modes and their respective failure effects.

Flue gas and scrubber system

The function of the flue gas and scrubber system is to provide flue gas at the proper pressure, temperature, and O_2 content to the tank vapor compressor suction header as a source of inert gas to blanket the oil storage tanks when loading ships without vapor control. In addition, flue gas is required for inerting the crude oil tanks prior to removing a tank from service and before returning a tank to service for the completion of inspection and/or maintenance activities.

Inert Gas Cooler

The coolers consist primarily of three functioning components: the heat exchanger section; the forced draft fans; and the intake, exhaust and recirculation louvers. The temperature of the flue gas supplied to the coolers can range up to 450°F and must be lowered to 120°F before being sent to the SO_2 scrubbers. The heat exchanger section of the gas cooler exposes the necessary heat transfer area to the cooling air supplied by the forced draft fans to cool the amount of flue gas flow required by one gas compressor operating at maximum output. The heat removal capability of each cooler is 4.16 million Btu/hr at rated conditions. Steam is supplied from the 20 psig steam system through an electro-hydraulic control valve which opens automatically when the cooler is removed from service and closes when the cooler is placed in service. The condensed steam traps to the hot condensate system. Each flue gas cooler contains two forced draft fans, each one of which is capable of supplying 56,000 acfm of air to the heat exchanger section. The fans are 9 feet in diameter and contain 4 blades, each having a manually adjustable pitch. The fans rotate at 320 rpm and are provided with a Murphy vibration switch to trip the fan on excessive vibration. The fans are driven by 15-

hp, 1,750-rpm, 460-volt, 3-phase electric motors through a V-belt and pulley arrangement with a speed reduction of 5.47 to 1. The coolers are equipped with intake louvers located on the cooler sides below the fans, exhaust louvers located in the top of the cooler housing, and recirculation louvers located in the air passages between the discharge and suction areas of the fans.

The RCM analysis identified 23 functions, 29 functional failures and 82 failure modes and their respective failure effects.

Nitrogen Air Compressor

Compressed air is generated by two dedicated two-stage dry screw air compressors for the nitrogen generation unit. Each air compressor has the capacity to provide adequate air to produce the maximum normal nitrogen requirements of the terminal. Air is drawn from outside the compressor building through two-stage filter. An inlet filter is also provided with each air compressor skid. The air flows through the first compressor stage to the intercooler, through second stage compressor and then finally through the after-cooler. The discharges of the two compressors tie together and flow to the air accumulator. The air accumulator provides surge volume for the Nitrogen generation skid.

The RCM analysis identified 67 functions, 71 functional failures and 141 failure modes and their respective failure effects.

5.1.1.3 Berth Loading Arms

Once crude oil reaches the Valdez Marine Terminal (VMT) it may be stored in any one of eighteen 510,000 bbls storage tanks. Storage is used primarily to accumulate the oil between the between tanker loading. Once a tanker is authorized by the Operations Control Center (OCC) ballast water is unloaded. Ballast water unloading and crude loading is achieved via 4 common loading arms which are connected to the tanker piping manifold. The loading arms must provide a leak free connection at all times during the unloading/loading operations or the affected loading arm(s), by law must be shutdown. As the crude itself is fed by gravity from the storage tanks, each tanker uses its own pumps to off-load the ballast water. The ballast water is directed through the Ballast Block Valve (BBV) to the Ballast Water Treatment plant (BWT) at a maximum hourly rate 90,000 bbls.

Once ballast unloading is completed, crude is then directed from the crude storage tanks through each of the four loading arms found at the each of the 4 berths at VMT. During crude loading, the crude oil is fed by gravity from the storage tanks or directly from the pipeline itself. Crude can be fed at a maximum rate of 27,500 bbls/hour per arm for a total of 110,000 bbls/hour. Small tankers are given a 24 hour window for loading crude from the time they begin to docking procedure. Large tankers are given a 30 hour window. On average a small tanker can be turned around in 16 hours and a large tanker 24 hours. Any failure which interrupts this cycle is considered unacceptable and is reported as a delay. Once the delay impacts the loading window, it may cause delays in the shipping schedules.

Berths 4 and 5 have been fitted with vapor recovery arms which direct the vapors generated during the loading process to dedicated vessel vapor compressors located in the compressor building. The vapor is pressurized, combined with vapors from the crude oil storage tanks, and used for vapor balancing of the tanks or used in the power plant boilers to reduce fuel oil consumption.

The RCM analysis identified 21 functions, 25 functional failures and 166 failure modes and their respective failure effects.

Berth Loading Arm Chicksan Hydraulic Skid

The Chicksan hydraulic skid provides hydraulic power to the loading arms and the quick disconnect (QDC). Once hydraulic functionality has been verified the arms are maneuvered into position. The QDC is opened to release the non-pressurized blank and open the jaws. The O-ring and QDC surface is wiped clean and the O-ring is visually checked for defects. Operators then guide the QDC jaws until it rests on the tanker flange. The enable button must be held in place while the coupler "close" is selected to close each of the three jaws. Once all three QDC screws stop or bottom out, the maximum amount of pressure will be applied. This process takes between two and three minutes on average and up to five minutes. The QDC's will remain engaged during the entire ballast unloading and the crude oil loading cycle, 24 hours for small ships and 30 hours. Once all the loading arms have been connected to a tanker, the hydraulic unit is turned off, which locks the valves downstream of the Christmas Tree (hydraulic lines actuating manifold) in a neutral position permitting all the Chicksan berth loading arms to free-float in response to changes in tide height, tanker position. Once the tanker is loaded with crude oil, the connection process is reversed until each arm has been has been stowed on the berth and secured against any potential movement. In the event the remote unit is not working the berth operator will typically control each of the arm connections and disconnections from the Chicksan skid.

The RCM analysis identified 19 functions, 26 functional failures and 74 failure modes and their respective failure effects.

5.1.1.4 Tanker Vapor Collection System

The VMT Tanker Vapor Control System was installed to meet the "National Emissions Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations" (40 CFR 63, Subpart Y). The Vapor Control System, from the vessel to the Power Generation/Vapor Recovery area point of connection, must also meet the Coast Guard regulations in accordance with the provisions of 33 CFR 154, Subpart E, "Vapor Control Systems." Vapors are generated as a tanker loads due to displacement of vapor by the incoming crude and generation due to the volatility of the crude. Vapors are collected from the vessels via two 16” vapor collection arms at Berth 5, and transported through dedicated vapor collection piping (one per berth) to dedicated vessel vapor compressors located in the compressor building. The vapor is pressurized, combined with vapors from the crude oil storage tanks, and used for vapor balancing of the tanks or used in the power plant boilers to reduce fuel oil consumption.

The Tanker Vapor Recovery System was broken down into four separate RCM analyzes: Fenwal Safety System, Oxygen Analyzers, Berth 5 Collection System and the Bailey DCS.

Berth 5 Vapor Collection Arm

Vapors are collected from the vessels via two 16” vapor collection arms with a quick disconnect coupling (QDC) on each arm to allow connection to the vessel’s vapor header flange. A butterfly valve on each arm is used to prevent air intrusion into the system or release of hydrocarbon vapors into the atmosphere. There is a Berth isolation valve, which acts as a separation point between the two parts of the vessel vapor collection system. The valve has several safety functions in terms of instrumentation permissives and interlocks.

The RCM analysis identified 39 functions, 44 functional failures and 145 failure modes and their respective failure effects.

Berth 5 Vapor Collection System Oxygen Analyzer

Berth 5 is equipped with two oxygen analyzers. Only one is required for operation, but if both analyzers are available, either can cause a high alarm or high-high shutdown. The high oxygen alarm will sound if the oxygen in the vapor collection piping exceeds 6.5% and high-high shutdown will activate at 7%. This shutdown will stop crude loading and shutdown the vapor collection system. These set points are more conservative than 8% stated in CFR 154. The United States Coast Guard (USCG) agreed to the shutdown requirement. The analyzers are required by 33CFR 154.824 (f-h) to continuously sample the vapor and have a response time of less than 30 seconds from sample to result. Several redesign recommendations were made to improve the overall reliability of the oxygen analyzers.

The RCM analysis identified 33 functions, 37 functional failures and 71 failure modes and their respective failure effects.

Berth 5 Vapor Collection Control

The Bailey DCS provides the overall process control of the Berth 5 Vapor Collection System.

The RCM analysis identified 58 functions, 54 functional failures and 132 failure modes and their respective failure effects.

Berth 5 Fenwal Safety System
The Fenwal Safety System is designed to protect against hydrocarbon deflagrations or detonations occurring in the vapor recovery piping installed on Berth 5. The system uses pressure detectors and infrared flame detectors to monitor the 26" diameter piping between the vapor collection points at the Berth and the onshore compressors. Each vapor recovery line has a high-speed explosion isolation valve coupled with dry chemicals extinguishing barrier on either side of the valve. The systems are designed to prevent either a deflagration or a detonation, originating in the process equipment or piping on one side of the arrestor, from propagating to the piping and process equipment on the either side of the arrester system. Fluidized sodium bicarbonate is used as the suppressant in these systems. This system has suffered from a number of premature activations, which has cost APSC three quarters of a million of dollars. Several recommendations were made, and have been implemented, to improve the overall reliability of the system.

The RCM analysis identified 51 functions, 63 functional failures and 136 failure modes and their respective failure effects.

5.1.1.5 Berth Fire Systems

The Berth fire system consists of redundant, normally dry firewater lines located on the berth causeway and tied into the onshore 30" fire main. An electric motor driven pump supplies seawater to a foam proportioning skid and to two 8" foam headers. The foam headers supply four foam monitors, two fire foam hose reels and a hose cabinet. Two of the monitors provide protection for the berth while the other two monitors provide coverage for a moored vessel. (Note: A "monitor" is the device that sprays the water foam mixture in a direction needed to fight the fire.)

Berth 4 Firewater Pump
The RCM analysis identified 30 functions, 31 functional failures and 47 failure modes and their respective failure effects.

Berth 4 Foam Concentrate Skid
The RCM analysis identified 35 functions, 39 functional failures and 48 failure modes and their respective failure effects.

Berth Instrument Compressor
The RCM analysis identified 56 functions, 87 functional failures and 161 failure modes and their respective failure effects.

5.1.1.6 Back Pressure Control System

Decreased North Slope production over the years has caused the pipeline crude flow to decrease from 2.1 million bpd at its peak to approximately 1.0 million bpd. The reduction in flow decreased low enough that at the Thompson Pass, where the elevation of the pipeline drops rapidly caused the crude oil to "free-fall" through this section of pipe to a lower elevation, called the packed line interface. This caused an underground section of the pipeline near the community of Heiden View, to start vibrating and as a result residents complained.

To resolve this problem, in 1998 the Thompson Pass Backpressure Control System was designed to maintain pipeline pressure at a constant 750 psig, so that the packed line interface is located at a higher elevation, 2200 feet elevation, some distance away from Heiden View. This kept pressure pulsations at or below 20 psi at all pipeline throughputs. The elevation is maintained by automatic control of five identical control valves. The backpressure control valves are controlled by two controllers operating through a low signal select. OCC has control of the pipeline backpressure controller on the upstream side of the valves, which will maintain the desired pressure at Thompson Pass.

Since the Thompson Pass Backpressure Control System was put into operation in late 1998, there have been a number of system failures. Many of these have been traced to the control valve hydraulic system components, particularly the Snap-Tites. This RCM analysis includes the electro-hydraulic actuators to operate the backpressure valves, which are to be installed under project Z259. The scope of this analysis starts with the MOV 008, includes all piping, valves, instrumentation etc., and ends at MOV 786. The analysis excludes the power supply system and hydraulic supply system.

The RCM analysis identified 29 functions, 44 functional failures and 101 failure modes and their respective failure effects.

5.1.1.7 Terminal Pressure Relief System

The main purpose of the pressure relief system is to respond to set points that have been established. The terminal mainline relief valves serve to limit the maximum operating pressure, which can be seen on both the pipeline and terminal crude piping. The pipeline pressure relief system has been designed to keep operating and surge pressures from exceeding 100 percent of the pipe's internal design pressure. The terminal piping relief controller is set for 300 psig to protect the ASME class 150 terminal piping in the tank farms. In the event the terminal relief controller opens the relief valves, the pipeline backpressure will drop to less than 300 psig in less than two seconds and backpressure control will be lost. The relief valve pressure setting for the pipeline can be set by the OCC controller to meet operational requirements. When the pipeline is operating on backpressure control the relief valves are normally set to 50 psig above the backpressure set points to prevent large pressure surges during relief events. As backpressure is ramped up and down the relief set points are ramped up and down with it. The current design places responsibility for maintaining these set points on the OCC controller. The relief controllers for both the pipeline and the terminal piping have a backup pressure switch, which is set for 875 psig and the terminal pressure switch is set for 350 psig. Either switch will open all four pressure relief valves. The relief valves are spring loaded to fail open and must be held closed by the hydraulic system.

The RCM analysis identified 28 functions, 32 functional failures and 86 failure modes and their respective failure effects.

5.1.2 Pipeline System

Mainline Pipe:
The pipeline extends from Prudhoe Bay to Valdez and is built in three modes, depending on environment, terrain, and soil conditions. The three construction modes are conventional burial, aboveground, and below ground insulated pipe.

Oil was originally received at temperatures as high as 145°F. The oil comes from the ground at temperatures as high as 180°F and currently enters the pipeline at about 115°F, depending on production rates and how the oil was handled before delivery to the pipeline from the entire North Slope production field. Because of heat generated by the pumping and the friction within the pipe, the oil at the design rate of 2 million barrels a day ranged from 140° F to 90° F as it moved through the system, depending on ambient temperatures. The oil currently reaches Valdez at about 60° F, depending on ambient temperature, at a flow rate of 1.0 mmbpd.

The type of soil and the effects of heat transfer from the oil to the soils along the route determined whether the pipe was buried conventionally, was specially buried, or was elevated aboveground. Special burial involves the use of a refrigeration system to keep permafrost soil around the pipe frozen.

The pipe was specially engineered and fabricated for the Trans-Alaskan pipeline. The 48" diameter steel pipe, was manufactured in three grades pipe (X-60, X-65, and X-70) and two wall nominal thicknesses (0.462" and 0.562"), has a minimum yield strength of 60,000, 65000 and 70,000 pounds per square inch. Maximum internal design pressures range from 700 to 1180 pounds per square inch. Generally, the higher grade of pipe with the heavier wall thickness is used where internal pressure is greatest as in pump station discharge line sections. Lighter pipe is used near the station suction. The pipe is coated and cathodic protection is provided to prevent bacteriological, chemical, and electrolytic corrosion. Even though not generally subjected to unusual forces and deformations, the pipeline is designed to sustain all expected hydraulic pressures, thermal forces, and stresses induced by settlement, compaction, earthquakes, and weight between supports of the elevated line, including snow and wind loads. Particular emphasis was placed on providing a high degree of assurance that the line will not leak oil.

Pump Stations:
The pump stations are irregularly spaced to meet hydraulic design requirements as the pipeline traverses the varying elevations of three mountain ranges. The stations are closer together on upslopes and more widely spaced on downslopes. Accessibility, soil characteristics, and environmental considerations were also factors in locating the stations.

Stations 1, 3, 4, 6, 8, 9, 10 and 12 were constructed for throughput of 1.2 million barrels per day. Pump Station 5, less mainline pumps, was also constructed to function as a relief or draindown station. Mainline pumps would have been installed at Pump Station 5 (if not for DRA) in conjunction with construction of Pump Stations 2 and 7 to accommodate the design capacity of 2 million barrels per day. At the rate of 1.2 million barrels per day, oil moves through the line at slightly more than 4 miles an hour and takes approximately 7-1/2 days to be pumped from Prudhoe Bay to Valdez. At full capacity, the oil travels at slightly more than 7 miles an hour and completes the trip in about 4-1/2 days.

Centrifugal pumps at each station are powered by 18,000-horsepower modified aircraft-type gas turbines. Fuel gas for the turbines at Pump Stations 1 through 4 is provided from the fuel gas pipeline extending from Prudhoe Bay to Pump Station. The other pump stations are supplied turbine fuel which was originally derived from the mainline crude oil by topping units at Pump Stations 6, 8 and 10. Pump Station 10 topping unit has now been decommissioned.

For the rate of 1.2 million barrels per day, three pumps, one in stand-by reserve, are installed at each pump station except Pump Stations 2 and 7 which only required two pumps. For the rate of 2 million barrels per day four pumps were to be installed, three operating and one standby, at each pump station. Higher flow rates were achieved using Drag Reducing Agent (DRA) instead of additional mainline pumps (DRA reduces frictional head loss).

Although the pump stations are similar to those on other pipelines, the trans-Alaska pipeline pump stations are specifically designed to meet the challenges of the Alaska environment. All the equipment and virtually all the station piping is housed in insulated, windowless buildings connected with covered hallways. Most of the pump stations are built on stable soils in a relatively conventional manner. However, five stations (1, 2, 3, 5 and 6) are erected on refrigerated gravel atop permafrost. Coils of pipe containing brine are buried in the gravel, beneath a plastic foam insulation mat, to keep the permafrost underlying the buildings frozen and stable.

Each station is equipped to supply all of the requirements of life for operations personnel. Except for PS 9 (where personnel live locally), every station has living quarters, food service, electrical generating facility, central heating plant, water treatment and storage facility, sewage and waste disposal system, station-wide fire detection system, and automatic fire-extinguishing facility.

The table below provides the status of TAPS sub-systems analyzed on the Pipeline using the RCMII process. Data totaling the functions, functional failures, and failure modes from each completed analysis is provided:

Trans-Alaska Pipeline System RCM Analyses – Pipeline

Complex System	Critical Sub-System	System/Equipment	Status	Analysis Results		
				Functions	Functional Failures	Failure Modes
➢		**Mainline Pipe**				
	✓	Mainline Buried Pipe	Completed	15	20	107
	✓	Mainline Special Bury Pipe	Completed	9	11	54
	✓	Mainline Refrigeration Units (MLR)	In process			
	✓	Brine System	In process			
	✓	Mainline Above Ground Pipe	Complete	43	50	155
	✓	Mainline Remote Gate Valves	Revisit Original			
	✓	RGV Ormat Energy Converters	Revisit Original			
	✓	Mainline Check Valves	Revisit Original			
		Pump Station				
➢		**Mainline Relief**				
	✓	Suction and Discharge Valves	Completed	19	29	73
	✓	Hydraulic Unit and Control System	Completed	30	53	83
➢		**Tanks**				
	✓	Crude surge/relief tanks	Completed	23	33	68
➢		**Heating and Ventilation Systems**				
	✓	Fire Emergency Ventilation	Completed	12	16	70
➢		**Fire/Gas Detection/Suppression System**				
		Pump Station 9 Manifold Building				
	✓	Fire Detection Systems				
	✓	UV Detection Systems	Completed	38	58	85
	✓	Thermal Detection Systems	Completed			
	✓	Manual Pull Downs	Completed	21	34	59
	✓	Gas Detection System	Completed			
	✓	Halon Suppression System	Completed	28	40	57
	✓	Unsupervised Systems	Completed			
		Pump Station 9 Pump Room				
	✓	Fire Detection Systems	Completed	38	58	87
	✓	Gas Detection System	Completed	21	34	60
	✓	Halon Suppression System	Completed	28	39	67
		Pump Station 9 Primary Generator Building				
	✓	Fire Detection Systems	Completed	21	41	55
	✓	Halon Suppression System	Completed	26	34	57
		Pump Station 9 MLU				
	✓	Fire Detection Systems	Completed	38	55	87
	✓	Gas Detection System	Completed	20	33	80
	✓	Halon Suppression System	Completed	27	36	57
		Pump Station 4 MLU				
	✓	Fire Detection Systems	Completed	38	55	87
	✓	Gas Detection System	Completed	20	33	80
	✓	Halon Suppression System	Completed	27	36	62
		Pump Station 4 Garrett				
	✓	Fire Detection and Halon Suppression System	Completed	14	29	62

Those systems with a "Revisit Original" status have already received an RCM analysis and APSC has scheduled a follow-up review as part of their continuous improvement process. The following sections describe an abbreviated operating context of each system analyzed. Attachment (5) provides specific task descriptions associated with each failure management decisions for failure modes identified as having hidden, safety, or environmental consequences. Attachment (7) provides Task Breakdown diagrams showing the number of identified tasks associated with each failure consequence type (i.e. hidden, safety, environmental, operational, and non-operational):

5.1.2.1 Mainline Buried Pipe

Generally, the safest mode of pipeline construction in stable soils is a conventionally buried pipeline. Therefore, the buried mode was used wherever the soils encountered permitted structural integrity criteria to be maintained. Ice rich permafrost could cause differential settlement of the soil in which the pipe is buried and could result in bending the pipe. Therefore, conventional burial was used only in areas where the soil was thawed, thaw stable, or bedrock. Burial depths range from 3 feet minimum cover over the top of the pipe to infrequent depths greater than 12 feet. The buried pipe was coated with an epoxy and wrapped with a polyethylene tape. However, where the pipeline has been repaired the pipe may now be coated with a wide variety of different materials.

The RCM analysis identified 15 functions, 20 functional failures and 107 failure modes and their respective failure effects.

5.1.2.2 Mainline Special Buried Pipe

The Mainline Refrigerated Pipe (MLR) exists in three locations totaling approximately 4 miles. The pipe is buried and insulated, and the surrounding soil is mechanically refrigerated to ensure that the permafrost remains frozen. The MLR #1 is located along the pipeline from milepost (MP) 647.281 to MP 649.183. The refrigeration plant is located south of the intersection of the Richardson Highway and P/L Access Road 27 AMS-4. This section of the pipeline contains Remote Gate Valve #97. The MLR #2 is located along the pipeline from MP652.0318 to MP 653.8316. The refrigeration plant is located north of the intersection of the Richardson Highway and P/L Access Road 26 APL-3. This section of the pipeline contains Remote Gate Valve #98A. The MLR #7 is located along the pipeline from MP 684.31 to MP 684.62. The refrigeration plant is located south of the intersection of the Glenn and Richardson Highways. This section of the pipeline contains the casing at the Glenn Highway crossing.

The mainline refrigerated pipe segments MLR #1 and #2 were designed and constructed to provide for the crossing of migrating caribou without hindrance.

MLR #7 provides the foundation integrity for the Glenn Highway pipeline crossing. The mainline refrigerated pipe is comprised of the following design elements: mainline pipe, polyurethane insulation and a fiberglass shell, six inch brine lines and a refrigeration plant to cool and pump coolant through the brine lines. The intent of the design is to permit buried pipe to be placed in permafrost soils which does not meet the requirements of Stipulation 3.3.1Construction Mode Requirements for belowground pipe. The brine used is 25% solution of calcium chloride with a corrosion inhibitor.

The ditch depth and width for special buried construction accommodates the bedding and padding of the brine coolant piping with a 3” minimum clearance from the ditch width wall.

The RCM analysis identified 9 functions, 11 functional failures and 54 failure modes and their respective failure effects.

5.1.2.3 Mainline Aboveground Pipe

The pipeline is constructed aboveground in areas where the soils become unstable if they are thawed by a buried pipeline. The aboveground portion of the pipeline consists of about 423 miles of pipeline constructed above the ground surface on vertical supports. About 78,000 vertical support members (VSMs) have been installed to elevate the pipeline in areas where soil conditions are unfavorable for pipe burial. Where there was high potential for thawing around a VSM which would lead to potential instability, the VSM was equipped with thermal devices called heat pipes which remove heat from the ground by non-mechanical circulation of ammonia in a pressurized tube.

VSMs typically consist of an 18-inch diameter steel pipe that is placed in pre-drilled 24-inch diameter hole backfilled with sand slurry or grout. The VSMs are installed in pairs connected by an elevated horizontal steel crossbeam. This assembly is called a bent. The pipeline is supported, but not secured, on steel shoes, which rest on the crossbeam with Teflon pads. The bents are typically spaced about 60 feet apart and the heights of the crossbeams are positioned to distribute the load of the pipe uniformly among the bents. Anchors, consisting of four VSMs, secure the pipe on intervals of approximately 800 feet to 1800 feet.

The RCM analysis identified 43 functions, 50 functional failures and 155 failure modes and their respective failure effects.

5.1.2.4 Mainline Relief System

Suction and Discharge Valves

There are two pairs of mainline pressure relief valves. The pairs are distinguished by the location of their sensors and the size of their piping. The suction relief valves are actuated by sensors on the suction (upstream) side of the mainline inside the manifold building and have 16” piping. The discharge relief valves are actuated by sensors on the discharge (downstream) side of the mainline inside the manifold building and have 12” piping.

In the event that mainline crude pressure rises at a rate of 75 psi in 5 seconds or less, the surge controller initiates the opening of the suction relief valves. The surge controller is located in the Station Control Panel and is adjusted internally.

In the event that mainline crude pressure exceeds certain set points, suction pressure switch and / or suction pressure switch controller actuates the hydraulic pressure control suction relief valves. The relief valves relieve excess pressure by allowing oil to flow into crude oil relief tank. In addition, the discharge pressure switch will shut down the station if pressure exceeds its setpoint.

In the event that mainline crude pressure exceeds the set point, the discharge pressure controller actuates the hydraulic pressure control discharge relief valves. The relief valves relieve excess pressure by allowing oil to flow into crude oil relief tank.

The RCM analysis identified 19 functions, 29 functional failures and 73 failure modes and their respective failure effects.

Mainline Relief Suction and Discharge Valves - Hydraulic Unit
The hydraulic unit provides power for four valves. The unit is located near the valves it serves. It is comprised of two separate but identical systems, which are supplied by a common reservoir and fed by common supply and return lines to the valves. The two systems do not operate together; they are redundant. If the primary system fails, the other starts automatically. The hydraulic units have two temperature switches in the fluid reservoirs. One switch detects a rising temperature, and at 135°F, it diverts the fluid flow through a 4-way valve to the heat exchanger before returning it to the reservoir. The second temperature switch is set at 145°F to 150°F. In this temperature range, the switch sounds a high temperature alarm, shuts down the system, and starts up the standby system. A hydraulic failure alarm is simultaneously transmitted to OCC.

The pumps are variable volume, pressure compensated, reciprocating piston pumps equipped with an adjustable maximum discharge volume preset at the factory. The pump compensator will automatically control the pump to an output volume that maintains the pressure in the system at all times, independent of system flow requirements. The electric motors that drive the hydraulic pumps operate at 480 VAC. They are 3-phase, 1,200 rpm, explosion-proof, arctic duty, double end shaft motor. One end of the shaft drives the pump and the other drives the heat exchanger fan. The discharge of each pump has a 3-micron, disposable type filter with differential pressure switch to indicate when the filter element must be replaced. Check valves are used to isolate the two pump circuits from each other and prevent back flow from the operating system into the standby system. There are two pressure activated switches on each system. One switch indicates system overpressure the other indicates system under-pressure. The switches cause a transfer from the operating pump to the standby pump if the system pressure becomes too high or too low. The accumulators are 10-gallon, bladder-type steel vessels pressurized with dry nitrogen and float on the system pressure. The accumulators supply fluid for very short periods of time to supplement the pump volume when the valve actuator demands more flow than the pump can supply or when a problem causes a temporary drop in discharge pressure.

The RCM analysis identified 30 functions, 53 functional failures and 83 failure modes and their respective failure effects.

5.1.2.5 Mainline Relief Tanks

The purpose of the tank is to temporarily hold the crude oil that discharges from the mainline pressure relief valves and to absorb surges in the flow of crude oil. Insulation is fitted on the lower 6 feet of the tank sidewalls. One electrically driven mixer is mounted on the side of the tank, 3 feet above the tank bottom. The electric motor and gearbox are heated electrically when they are not operating. The mixer stops automatically when the liquid level falls to a preset level above the tank base.

Pressure/vacuum valves are set to open at 1.5 inches water column (WC) pressure and at 1-inch WC vacuum. Each tank is equipped with two additional emergency vents that relieve at 4 inches WC. This crude tank has a fin-tube heating element mounted18 inches above the tank base, and is supplied thermal heating fluid from the station heating sys-tem. The temperature of the tank contents is maintained at a minimum of 40°F. A temperature sensor is located above the tank base. The temperature is displayed on the station control panel. A temperature switch is mounted near the base of the tank This switch is set at 175°F. If the tank oil reaches this temperature, an alarm on the station control panel is annunciated. A high level switch is located near the top of the tank. It initiates an alarm on the station control panel annunciator when the oil level in the tank reaches this point. The switches are heated. A low level switch is installed above the tank base. The switch initiates an alarm on the station control panel annunciator. A low level switch is installed above the level low switch to stop the mixers when the oil level falls to the preset level. A float-type level with stilling well is fitted to the tank. The gauge has a local reading and a level transmitter with level switches. The transmitter sends a level signal to the indicator on the station control panel. A heating element is fitted to the level switch unit. The level switches on the float level gauge supplement the fixed switches in the wall of the tank, and they are set at the same level as the fixed switches they back up. Four water draw-off ports are located in the tank with the base of the ports 2inches above the base of the tank.

The RCM analysis identified 23 functions, 33 functional failures and 68 failure modes and their respective failure effects.

5.1.2.6 Heating and Ventilation – Fire Emergency Ventilation

Normally, the pump station buildings are ventilated with a positive pressure, fan- or blower-driven supply of outside air. Most buildings, under certain emergency conditions, bring in an additional positive supply of outside air. All buildings have exhaust ventilators. Few exhaust ducts contain fan-driven exhaust equipment. In several buildings, supplemental ventilation is provided for summertime cooling. All normal air supply and emergency air supply air (with the exception of the flammable liquids building) is heated by passing air over a finned, tube-type, heat exchanger coil. The temperature of this heated supply air is controlled by individual temperature sensing control valves at each heat exchanger coil. Normal supply fans have the control valves mounted near the floor. Emergency supply control valves are ceiling mounted. Each ventilator, whether it is a fan-driven supply, exhaust, or only an exhaust duct, is equipped with a motor-operated damper which is electrically actuated to the open position and is spring-loaded to the closed position. These damper controls, along with supply and/or exhaust fan controls, are located in the motor control centers.

The emergency ventilation switches on the MCC panels are hand-auto switches. Emergency ventilation may be turned on manually by placing the switches in the hand position; however, during normal operations these switches are in the auto position. In the “auto”switch position, the hazardous gas detection system activates the emergency ventilation mode upon detection of a 20% LEL (lower explosive level) concentration of gas in any given building or building zone. When the hazardous gas condition is cleared (unlatched) on the fire control panel, the ventilation system will return to the normal ventilation mode. At 50% LEL the fans stop, the dampers close, and in crude process areas, the Halon fire suppression system is activated. A fire detection signal (thermal or ultraviolet sensor activated) will turn off all ventilation fans and close all dampers in an affected zone regardless of the positions of the MCC ventilation switches. When the fire condition is cleared on the fire control panel, the ventilation system will return to the mode it was in prior to fire shutdown.

The RCM analysis identified 12 functions, 16 functional failures and 70 failure modes and their respective failure effects.

5.1.2.7 Pump Station Fire and Gas Detection and Halon Suppression System

Alyeska Pipeline Service Company utilizes fire and gas detection systems and Halon suppression systems to detect and inert or suppress potential explosions and actual fires. The primary purpose of these systems is to protect personnel. The secondary purpose is to protect facilities and equipment.

Major functions performed by the fire detection and suppression systems are:

- Monitor hydrocarbon gas levels
- Detect smoke
- Detect flames
- Detect excessive temperatures
- Alert personnel to a hazardous atmosphere or fire condition
- Automatic activation of emergency ventilation system
- Isolation of hydrocarbon sources
- Automatic shutdown of equipment
- Automatic discharge of Halon in a hazardous atmosphere/fire zone
- Manual activation of Halon and/or foam in a hazardous atmosphere/fire zone

The ultraviolet (UV) flame detection system detects the ultraviolet rays produced by the flames of incipient (beginning) fires rather than rays produced by naturally occurring light. The UV systems provide nearly instantaneous fire detection response of less than 25 milliseconds, typical. Alyeska has selected the maximum sensitivity for UV detection, rendering the detectors vulnerable to occasional false alarms. A 2-second time delay is used for the alarm relays. The delay relays are only used in "voted" areas and the primary generator room. A voted area is an area containing critical equipment monitored by more than one UV detector. In voted areas, a UV source (flame, etc.) must be seen by two detectors before any action can take place. Voted areas can be physically identified by finding UV detectors placed to permit overlap within the arc area of the view windows. Other areas use instantaneous (25 ms) alarm relay contacts.

Ionization detectors detect products of combustion in the incipient stage prior to the release of visible smoke. The detectors are especially effective for detecting fire in electrical conduit cable trays in hallways. Ionization detection is also used for smoke detection in office buildings (including crawl spaces), generator rooms, control rooms, and personnel living quarters (PLQs). An ionization alarm in one of the areas will be annunciated in the Station Control Room. Ionization detectors are alarm only, and do not dump Halon or shut down process equipment. Ionization detectors use a radioactive element to detect combustion products, but they are not dangerous in normal use.

Thermal detectors, with normally open contacts, operate by closing contacts in response to a high or rapidly rising temperature. Thermal detectors are used with the following temperature ratings: 140°F, 190°F, and 22°F. However, Garrett enclosures use 325°F thermal detectors. The early warning rate compensation feature closes a thermal detector before reaching its fixed set point.

Manual pull stations (PHDs) are located in pump station hallways and mounted on AMI boxes. Pull stations are simple two-pole switches: one pole is wired on an area's fire panel zone, and the second pole is wired directly to the fire relays (FX).

Manual pull stations permit manual shutdowns and Halon dumps when the fire control system fails or the isolate switches are active. Control room PHD switches and hallway-located manual pull switches perform identical functions.

The gas detection system provides the pump stations with early detection and warning of the presence of hazardous atmospheres so that appropriate safety steps may be taken. The gas detection systems use Varigraph 16 gas monitors. The Varigraph 16 offers 16 gas detection channels per monitor. Each channel has a plug-in light emitting diode (LED) display board and a plug-in relay board.

A Halon supervision and test panel (HSTP) continually monitors the integrity of fire panel circuits that control the discharge of Halon and various shutdown functions. The HSTP may be thought of as having two parts: the HSTP and the RHDP (remote halon discharge panel). The RHDP contains the firing relay (KF) which discharges Halon and performs such functions as under voltage detection, testing bypass, discharge time limiting, and damper fuse supervision. The HSTP is a stand-alone system. In the event of an HSTP shutdown, the fire alarm and suppression system is not compromised. Loss of power to an RHDP, however, will inhibit the discharge of Halon.

Halon is the agent used for inerting hazardous atmospheres and suppressing fires. Automatic discharge of Halon in response to a hazardous atmosphere and/or fire condition is the primary control function of the fire detection and suppression systems for the pipeline field facilities. Whenever Halon is discharged, ventilation equipment is automatically shut down. Should the automatic discharge of Halon fail, the manual discharge of Halon for a hazardous atmosphere and/or fire condition is the primary backup. Manual discharge of foam is the secondary backup to the discharge of Halon in a hazardous atmosphere or fire condition.

Manifold Building Fire/Gas Detection and Halon Suppression System
This system was sub-divided into three separate RCM analyses; fire detection, gas detection and Halon suppression. The three analyses identified a total of 87 functions, 132 functional failures and 201 failure modes and their respective failure effects.

Pump Room Fire/Gas Detection and Halon Suppression System
This system was sub-divided into three separate RCM analyses; fire detection, gas detection and Halon suppression. The three analyses identified a total of 87 functions, 131 functional failures and 214 failure modes and their respective failure effects.

Primary Generator Building Fire/Gas Detection and Halon Suppression System
This system was sub-divided into two separate RCM analyses; thermal detection and Halon suppression. The two analyses identified a total of 47 functions, 75 functional failures and 112 failure modes and their respective failure effects.

Pump Station 9 Mainline Unit Fire/Gas Detection and Halon Suppression System

This system was sub-divided into three separate RCM analyses; fire detection, gas detection and Halon suppression. The three analyses identified a total of 85 functions, 124 functional failures and 224 failure modes and their respective failure effects.

Pump Station 4 Mainline Unit Fire/Gas Detection and Halon Suppression System

This system was sub-divided into three separate RCM analyses; fire detection, gas detection and Halon suppression. The three analyses identified a total of 85 functions, 124 functional failures and 229 failure modes and their respective failure effects.

Pump Station 4 Garrett Fire Detection and Halon Suppression System

The RCM analysis identified 14 functions, 29 functional failures and 62 failure modes and their respective failure effects.

5.2 RCM Results Implementation

The APSC Implementation Process

Implementing the results of an RCM analysis can be the more difficult element to achieve, as it requires management and coordination of the 12 elements listed in the above section *4.2 Asset Maintenance Management Assessment*. The first step in implementation is to import the resulting RCM tasks into the company's Computerized Maintenance Management System (CMMS), *Passport*. The tasks are then scheduled and the appropriate resources assigned.

From JPO's current understanding of the RCM task implementation process at APSC, the following is provided to summarize the process: The first step is the management audit. The senior managers with the overall responsibility for the asset subjected to the RCM analysis, take care to satisfy themselves that they agree with the analysis. This normally entails a formal review of the contents of the RCM information and decision worksheets. Following the management audit meeting the recommendations are implemented as follows:

- Maintenance tasks are grouped and assigned to an individual or individuals to develop job procedures and maintenance work orders (MWO's). A due date is targeted and entered in Passport Action Tracking.

- Changes to operating practice are grouped and assigned to the person responsible for the development or revision of Safe Operating Procedures (SOP's). A due date is targeted and entered in Passport Action Tracking.

- Training issues are identified and responsibility assigned and a due date for completion is targeted and entered in Passport Action Tracking.

- Equipment redesigns are reviewed, prioritized within the consequence evaluation framework and assigned to responsible individuals with a targeted due date and entered into Passport Action Tracking.

Task Assignments

1. Maintenance Activities

   All the proposed tasks make up the maintenance requirements for the asset under review. Each failure mode resulting in a maintenance task will likely fall into either a predictive (condition-based task), preventive or failure finding task. The proposed task states clearly what needs to be done, what performance standards (if any) apply to the task and which part of the machine or which component is affected. Typically the maintenance planner or scheduler is often in a better position to describe the task in the form of an activity. Activities are then grouped into logical executable work packages to form the basis of a maintenance work order. The work order contains all the pertinent information regarding: special tools, lockout procedures, safety procedures, etc.

2. Operating Activities

   Tasks, which require modification to or the generation of an operating procedure, are written into usable task steps or procedure instructions. Often a number of tasks can be seen in one Safe Operating Procedure (SOP). Where daily routines are identified, a simple checklist may be an appropriate method of collating these tasks. Depending on the current assignments, one or more operational supervisors, or operators may be involved in writing these procedures.

3. Redesign

   RCM identifies redesign by failure consequence. Multiple failures and single failures, which have safety or environmental consequences, are regarded as compulsory and need to be addressed first and foremost. However, if the compulsory redesign is impractical and the risk is considered to be tolerable, then it can be dismissed. Operational and non-operational redesigns are at the discretion of management. Where redesigns can be addressed by simply modifying worker behavior these are handled as described above regarding safe operating procedure changes or training.

> The development of all design changes still needs to incorporate the knowledge and understanding developed by the RCM review team as it relates to avoiding hidden failures and functions whose failures may result in safety and/or environmental consequences. Additional guidance should be sought from the respective RCM review team once the redesign has been developed.
>
> The RCM review team is then able to analyze the redesign against the RCM framework to understand the modification, develop the necessary maintenance and operational tasks required to put the item into service and ensure the best system integrity prior to procurement and commissioning.

Follow-up is carried out throughout the implementation of the RCM recommendations by the each action item being entered into the Passport Action Tracking system.

A Word on RCM and Maintenance Process Improvement
The application of RCM leads to a much more precise understanding of the functions of the assets which have been reviewed, and a much more scientific view of what must be done to cause them to fulfill their intended functions. However, the analysis will not be perfect – for two reasons:

- Numerous decisions have to be made on the basis of incomplete or non-existent hard data, especially about the relationships between age and failure

- The assets and their associated operating contexts may be changing continuously. This means that even parts of the analysis, which are wholly valid, may become invalid due to change.

The people involved in the analysis will also change. This is partly because the perspectives and priorities of those who take part in the original analysis inevitably change over time; and partly because people simply forget things. In other cases, people leave and their places are taken by others who need to learn why things are as they are.

All these factors mean that both the validity of the RCM database and people's attitudes towards it will inevitably deteriorate if no attempt is made to prevent this from happening.

To ensure that the RCM databases remain current, asset managers should consider bringing the original review group together on an annual basis to validate the original analysis. Such a review need not last longer than one afternoon. This is a continuous improvement effort.

RCM Implementation Verification
As APSC proceeds with implementation, JPO will be conducting periodic checks to validate accomplishment of the tasks prescribed to address the failure modes identified as having hidden, safety, or environmental consequences. These checks will be documented as JPO surveillance or technical reports; allowing JPO (and APSC) to track maintenance implementation (and therefore sub-system function preservation) in a very quantifiable manner. Monitoring implementation of the RCM results will be a core CMP element for ongoing JPO oversight.

5.3 GRANT/LEASE COMPLIANCE ISSUES

The following describes the RCM analysis results pertaining to the issues deferred from the JPO report, *Examining Grant & Lease Compliance*, and as described in section 4.4 above:

5.3.1 Slope Stability

The pipeline traverses numerous slopes along its route. Some of these slopes are steep, some have ice-rich soils or other soil conditions that make them susceptible to down slope movement. The TAPS design considers all slopes greater than 10% to be significant slopes. These slopes must be designed to withstand a Design Contingency Earthquake. For static conditions the calculated factor of safety for the slope must be at least 1.5. For dynamic loads the slope must be capable of resisting dynamic stresses with total slope movements no greater than 5 inches.

In light of these requirements the following function was defined during the Above Ground Pipe RCM analysis:

To maintain slope stability on all slopes exceeding 10% and 25’ of vertical height to a minimum static safety factor of 1.5 and a dynamic safety factor of 1.0 with less than 5” of ground movement under dynamic conditions, with the following exceptions:

- At Squirrel Creek where the static safety factor is 1.8 and the dynamic safety factor is 0.9 with less than 7” of ground movement under dynamic conditions, and

- At Pump Station 11 Hill where the static safety factor is 1.3 and the dynamic safety factor is 1.0 with less than 5” of ground movement under dynamic conditions.

The RCM analysis then went on to define three functional failures for the above function, which were generally defined as the inability of the slopes to meet any of the above criteria. The analysis then identified twenty-five likely causes (failure modes) that would result in a slope being in a failed state. The respective failure effects of each failure mode was described in detail to enable the review group to assess failure consequences. The consequences were evaluated for each failure mode and a failure management policy was determined to preserve the above function. The analysis concentrated on the following slopes to identify the maintenance requirements that would be representative of slope stability across the pipeline:

- Klutina Hill
- Tazlina Hill
- Treasure Creek
- Lost Creek
- Squirrel Creek and
- Pump Station 11 Hill.

The following maintenance requirements and their respective frequencies were identified for these slopes in order to maintain slope stability:

Failure Mode	Maintenance Task	Task Frequency
Slope surface disturbances cause ground to thaw	Monitor the slope stability of the following slopes using inclinometers, thermistors and extensionometers: • Klutina Hill • Tazlina Hill • Treasure Creek • Squirrel Creek • Pump Station 11 Hill	Every 6 Months
Klutina Hill wood chip insulation washed away	Check Klutina Hill wood chip insulation for coverage as per MS-31	Every 3 Months
Lost Creek deep seated thawing and thick work pad fill	Visually check Lost Creek down slope movement	Every 2 years
Slope VSM heat pipe fails due to hydrogen blockage	Check VSM heat pipe performance using infra-red camera and analyze results with empirical algorithm developed by systems integrity	Every 3 years
Slope VSM heat pipe repair mechanism leaks	Check VSM heat pipe performance using infra-red camera and analyze results with empirical algorithm developed by systems integrity	Every 3 years
Slope environmental changes lead to degradation of permafrost	Check VSM split ring elevations and VSM tilt. Compare to sub surface soil conditions and then perform analysis of the VSM using the VSM stability algorithm developed by systems integrity	Every 5 years

5.3.2 Fault Crossings

Three potentially active fault zones that cross the TAPS route were identified in the fault study: Denali, McGinnis Glacier, and Donnelly Dome. The recommended design movements for the three crossings are summarized in the table below:

Fault Location	Horizontal (ft)	Vertical (ft)
Denali	20	5
McGinnis Glacier	8	6
Donnelly Dome	3	10

In light of these requirements the RCM review group defined the following three functions:

- To allow the pipeline at the Denali Fault to respond to a 5’ vertical and a 20’ lateral earth movement in the event of a crust deformation
- To allow the pipeline at the McGinnis Fault to respond to a 6’ vertical and a 8’ lateral earth movement in the event of a crust deformation
- To allow the pipeline at the Donnelly Dome to respond to a 10’ vertical and 3’ lateral earth movements in the event of a crust deformation.

The RCM analysis then went on to define the functional failures, failure modes and failure effects for the above three functions. The failure consequences were assessed and suitable failure management policies identified. The table below summarizes the results of the analysis for each fault function:

Fault	Failure Mode	Maintenance Task/Poicy	Frequency
Denali	Dirt builds up on the steel beam	Check for dirt build up on the steel beam at the Denali fault	Every 5 years
	Denali fault teflon pad deteriorates	Check Denali fault Teflon slide plate for deterioration or damage	Every 5 years
	Pipe is incorrectly positioned at Denali fault	Check the position of the pipe at the Denali Fault	Every 5 years
	Grade beam length too short	Evaluate whether risk is acceptable *	
McGinnis	Aufeis freezes the shoes to the beam	Check for Aufeis build up underneath the anchors and/or intermediate supports	Every 2 weeks during winter months
	Intermediate bent Teflon pad deteriorates	Check Teflon slide plate for deterioration or damage at the McGinnis Fault	Every 5 years
Donnelly Dome	Intermediate bent Teflon pad deteriorates	Check Teflon slide plate for deterioration or damage at the Donnelly Dome Fault	Every 5 years

* Note: JPO will review the risk assessment to determine if corrective action is required under stipulation 3.4.2.

5.3.3 Pipeline Movement (Hydraulic events)

The issues of concern here regard pipeline movement caused by hydraulic events. The effect of TAPS hydraulic events concern functions associated with the control and response of Remote Gate Valves and Check Valves. RCM analyses were completed by APSC in July 1998, however they were never implemented. These original analyses will be the subject of RCM reviews commencing summer 2002. The reviews will evaluate valve control functions.

5.4 RCM AND RISK-BASED OVERSIGHT

As discussed in section 3.2 above, this CMP effort included a review of selected TAPS risk assessments in conjunction with the results of the RCM analyses. This provided a linkage between to the results of the risk assessments and the maintenance actions identified in the RCM analyses which protect against high risk, high consequence failures. Attachment (8) provides tabular results of this review.

Risk management is a strategic process aimed at reducing both the likelihood and severity of hazardous events. Risk analyses are tools that use previous history (statistics) as well as engineering-probability models to predict the risk of hazardous activity. The results can be integrated into a decision-making process to better understand risks, manage risks at an acceptable level, minimize cost, and prioritize expenditures.

The TAPS risk analyses provide an indication of the probability and severity of a leak at various locations along the pipeline. An effective pipeline risk management program then uses the risk analysis to allow a company to become more "proactive" and less "reactive" in the management of their pipeline. To manage the risks along the pipeline and at the Valdez Marine Terminal, APSC has an ongoing risk assessment program that helps to understand risks and minimize the potential for negative impact of TAPS on the public and the environment.

The primary objective of this JPO risk assessment review was to evaluate the four major risk assessments performed on TAPS over the last 10 years (Capstone, 2001; Taylor, 1995; Booz-Allen, 1994; Technica, 1991), and link the results of the pipeline RCM analyses (i.e. potential failure modes and associated failure management policies) to each of the identified risk categories. The risk categories were identified as the most likely causes of leaks that could occur along the pipeline.

In general these risk analyses were a quantitative assessment of the risks for various sections of the pipeline. These assessments used historical data, predictive models based on engineering calculations, and expert opinion, to determine the likelihood of a leak, and provide a rough estimate of spill volumes.

The general conclusion drawn from this review is that the risk-based approach used to identify the general causes of pipeline leaks was sound. Additionally, the linking of specific failure management tasks to each cause provides a continued basis for managing the risks associated with operation of TAPS.

6.0 Conclusions

6.1 TAPS Maintenance and Sustained Useful Life

The JPO oversight effort presented in this CMP report, and the one previous, was partially conceived to address the "useful life" determination necessary for renewal of the Grant & Lease. As previously presented, the JPO considers the "useful life" of TAPS to be directly related to the design criteria used to build TAPS and the maintenance strategies deployed to preserve the associated functional requirements throughout the life of the system. As such, JPO intends that APSC continue to demonstrate a commitment to a maintenance management strategy that ensures operational safety, environmental responsibility, and functional reliability, throughout the operational life of TAPS.

JPO has observed that while essential elements for effective maintenance management are in place, opportunities for improvement exist, and associated business processes must be updated, primarily in the areas of *Work Identification* and *Work Implementation*. Current APSC processes for identification of maintenance work are augmented by the RCM methodology, as RCM facilitates formulation of maintenance strategies that link specific actions to the preservation of system functions. Complete implementation of identified maintenance work may be enhanced through more efficient use of the APSC Computerized Maintenance Management System (CMMS), Passport. Specifically, a hierarchal-based (TAPS physical system hierarchy) data management system may be an improved tool for managing TAPS maintenance in a comprehensive manner.

Throughout this CMP effort, APSC has worked cooperatively to conduct RCM analyses of complex TAPS systems. The result has been the implementation of a structured, disciplined, and documented approach to TAPS maintenance. APSC has committed, via a Memorandum of Agreement (MOA), dated June 27, 2002, to continue to maintain TAPS in a manner consistent with the intent and terms of the Federal *Agreement and Grant of Right-of-Way* and the *Alaska State Lease of Right-of-Way*, and to revise the TAPS Maintenance Manual, MP-167, to align with the RCM program incorporated through this CMP effort. Attachment (10) provides a copy of this MOA. The commitments of this MOA represent a commitment on the part of both APSC and the JPO to continuously evaluate the maintenance practices employed on TAPS.

Based on the RCM analyses conducted to date, and the associated programmatic changes APSC has made to its TAPS maintenance strategies, JPO concludes that the physical life of TAPS can be sustained for an unlimited duration. Further, the commitments made to JPO through the various MOAs presented in this report, serve to demonstrate APSCs willingness to work cooperatively with JPO to continue to sustain TAPS in a functionally reliable state.